BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2019-184-E

South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Dominion Energy South Carolina, Inc.'s Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	)))))))))))))	Docket No. 2019-184-E

DIRECT TESTIMONY OF ED BURGESS

ON BEHALF OF

THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

SEPTEMBER 23, 2019

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I. TESTIMONY SUMMARY

Q. Can you please provide a brief overview of your testimony?

A. Yes. My testimony can be summarized as follows.

First, I provide background information on:

- The underlying utility incentive structures that may influence DESC's proposed avoided cost rates in this proceeding, and
- The potential costs and risks to DESC's customers from traditional resources versus QF resources.
- The importance of a technology-neutral approach to setting QF rates

Second, I provide an analysis and critique of issues related to DESC's proposed avoided energy cost rates, including:

- Lack of modeling transparency, including the selection of pricing periods
- Inclusion of excessive integration costs within the energy rate for solar QFs
- Inappropriate treatment of storage in several aspects

Third, I provide an analysis and critique of DESC's proposed avoided capacity cost rates including:

- Capital costs used for new and purchased capacity
- Assumed capacity value of solar QFs

Fourth, I provide an analysis and critique of DESC's proposed integration charge including:

- Statutory guidelines under Act 62 for completing an independent integration study;

- Deficiencies in DESC's modeling approach that do not match real-world operations;
- Background on integration costs more broadly.

Finally, I present alternative approaches for calculating the avoided cost rates for energy and capacity that correct for the deficiencies described above. Additionally, I recommend that the Commission reject DESC's proposed integration charge (as well as the integration cost component of DESC's proposed solar QF rates) until the independent study authorized by Act 62 is completed. In the event that a future integration charge is adopted, I provide a framework for how such a charge could be determined.

II. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please summarize your professional and educational background.

A. Currently, I am a leader on Strategen's consulting team and oversee much of the firm's work with its governmental clients, non-governmental organizations and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have managed or supported projects for numerous client engagements related to policies, programs, and rate designs for distributed energy resources, including renewable energy, electric vehicles, energy storage, and demand-side management. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and appeared before the Corporation Commission on a variety of solar-related issues. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in Sustainability, also from Arizona State. I also have a Bachelor of Art degree in Chemistry from Princeton University. A full resume is attached in Exhibit EAB-1.

Q. Please further detail your experience with avoided costs and related issues.

A. I have been involved with numerous state regulatory proceedings related to compensation for distributed resources including avoided cost, cost effectiveness, net energy metering, and value of solar. This includes proceedings in states such as New Hampshire, New York, Arizona, California, and Massachusetts. My clients have ranged from consumer advocates, non-governmental organizations, solar energy trade associations, and project developers. My role in these proceedings has ranged from conducting technical and economic analyses, drafting testimony and public comments, providing strategic guidance, participating in technical sessions and working groups, and appearing as an expert witness at evidentiary hearings.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the South Carolina Solar Business Alliance ("SBA"). Members of SBA include Independent Power Producers that sell the output of their facilities to incumbent utilities like DESC pursuant to the Public Utility Regulatory Policies Act, 18 U.S.C. Sec. 824a-3, *et seq.* ("PURPA"). Strategen was selected to support the SBA in this proceeding of the South Carolina Public Service Commission ("PSC").

Q. What is the purpose of your testimony?

A. My testimony will address the avoided cost rates proposed by Dominion Energy South Carolina, Inc. (DESC). I will provide a critique of the methodological choices used by DESC to calculate avoided costs and present several recommendations. I will also present an alternative calculation of avoided cost for the Commission's consideration.

Q. Have you ever testified before this Commission?

A. Yes. I recently submitted testimony in Duke's avoided cost proceeding in Dockets 2019-185-E and 2019-186-E.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I testified on behalf of the Massachusetts Attorney General's Office (AGO) at the evidentiary hearings for D.P.U. 18-150 (general rate case for National Grid) and for D.P.U. 17-140, which was directly related to compensation for distributed solar generation. I have also supported the AGO as a technical consultant in other recent cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and D.P.U. 17-146. Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at state Public Utilities Commissions including Arizona, New Hampshire, Nevada, Oregon, Pennsylvania, North Carolina, Maryland, District of Columbia, New York, Minnesota, Ohio, at the Federal Energy Regulatory Commission, and at the California Independent System Operator ("ISO").

Q. How is your testimony organized?

A. My testimony is presented in eight sections. Section I is a summary of my observations and recommendations. Section II is this introduction. Section III describes the inherent bias utilities like DESC have to establish low avoided cost rates for QFs. Section IV discusses how QFs help to contain costs and reduce risk for customers. Section V provides my assessment of the Company's choice to differentiate AC rates by technology and recommends an alternative. Section VI provides my assessment of the Company's approach to determining avoided energy cost rates and recommends an alternative approach. Section VII addresses my assessment of the Company's approach to avoided capacity cost rates and recommends an alternative. Finally, Section VIII provides my assessment of the Company's method for calculating variable integration costs and recommends an alternative approach.

III. UTILITY BIAS TOWARD LOW QF RATES

Q. What considerations should be taken into account regarding utility incentives before discussing DESC's avoided cost calculations?

A. The calculation of avoided costs is generally portrayed as a precise and scientific exercise. However, it is important to recognize that some level of uncertainty is inherent and unavoidable in most aspects of the electric power system, including the models and forward-looking projections used to calculate avoided costs. In addition, the person(s) calculating avoided costs must make a number of subjective choices about the model inputs, assumptions, and methodologies. Each of these choices may influence the outcome one way or another. Since the initial starting point of this proceeding is the utility's proposal, it is useful to understand what underlying financial incentives utilities have to make those choices in a way that tends to result in lower avoided cost calculations, and whether there is cause for the utility to submit a proposal that contains certain biases.

Q. What incentives related to avoided cost rates should decision-makers consider when evaluating DESC's proposal?

A. As a publicly traded company DESC has an obligation to maximize returns for its shareholders. DESC's profit maximizing responsibility gives it at least two important incentives regarding avoided cost rates. The first is that DESC, like other vertically integrated utilities, can maximize profits for shareholders by building and owning its own sources of generation. The second is that DESC's business model incentivizes the company to maintain or increase natural gas consumption in the region.

Q. Why is DESC incentivized to own its own sources of generation, even if this is economically inefficient from a system perspective?

A. Because regulated utility companies earn an authorized rate of return on invested capital in rate base, they can increase total shareholder earnings by making new capital investments[1]. Thus, it is logical for DESC to pursue sole ownership of generation assets, rather than

[1] This is also commonly known as the Averch-Johnson Effect, https://en.wikipedia.org/wiki/Averch%E2%80%93Johnson_effect

enable competitive generators such as QFs to crowd out potential utility owned assets. This is because these competitors could obviate the need for utility-owned generation, thereby reducing future investment opportunities for DESC's shareholders.

Q. How could this bias towards utility capital expenditures affect the utility's avoided cost proposal in this proceeding?

A. In order to exclude potential competitive generators and maintain its ownership of generation resources, DESC has an incentive to propose artificially low avoided cost rates and impose other barriers to competitive generators, such as the variable integration charge.

Q. Why is DESC incentivized to maximize natural gas utilization in its service territory?

A. DESC is affiliated with other subsidiaries under its holding company that own and operate natural gas transmission and distribution pipelines in the region.[2] In addition, Dominion Energy provides retail gas service in South Carolina. Thus, DESC has a vested interest in increasing the overall throughput of natural gas both in terms of wholesale sales, retail sales, and pipeline expansion opportunities.

Q. How does this natural gas bias affect the utility's avoided cost proposal in this proceeding?

A. Natural gas is a major fuel source for electric power output from plants in South Carolina that may be offset by solar QFs. Therefore, the more QFs participating under avoided cost rates, the less natural gas throughput there may be through DESC-affiliated pipelines. This

[2] For example, see DESC's recent presentation to investors, at page 14, https://s2.q4cdn.com/510812146/files/doc_presentations/2019/03/2019-03-25-DE-IR-investor-meeting-general-session-vTCII-website-version.pdf

contradicts the economic incentives of the broader DESC holding companies. Thus, DESC has an incentive to propose artificially low avoided cost rates and impose other barriers to competitive generators, such as the solar integration charge.

Q. Is DESC's proposed Avoided Cost methodology and resulting rates biased towards lower QF rates for solar?

A. Yes. While there is no single overriding factor that causes QF rates to be lower, DESC has made many small but meaningful methodological choices that each drive rates down incrementally. These smaller factors combine to create a resulting QF rate that is, in the aggregate, significantly biased against solar QFs.

Q. Can you provide a list of these individual factors that appear to be biased against solar QFs?

A. Yes. Some of these factors include the following:

- Selection of the time periods used to calculate the avoided energy cost rates.
- Model results that counterintuitively favor the non-peak season, when solar is less available.
- Inadequate analysis of solar plus storage operational capabilities.
- Selection of very low capital costs for a new peaker plant that are in turn used to calculate avoided capacity cost rates.
- Inappropriate assumption that the avoided capacity value for solar QFs is zero.
- Inclusion of both a Variable Integration Charge for existing QFs based on an analysis with flawed methodologies and input assumptions.

- Inclusion of presumed integration costs for future QFs based on a flawed analysis.

IV. IMPACT OF QF RATES ON UTILITY CUSTOMERS

Q. Please describe how QF rates impact the electric utility's revenue requirement recovered from consumers.

A. The rates paid out to QF resources are included in the electric utility's revenue requirement recovered from customers. The increased revenue requirement due to additional QF resources on the utility's system should in theory avoid a cost the utility would have incurred on a one-to-one basis. However, accurately reflecting the actual costs that QF resources avoid is a task subject to significant uncertainty. Thus, it is useful to consider setting QF rates that are within a "zone of reasonableness." The "zone of reasonableness" refers to the range of possible QF rates derived from inherently uncertain inputs and methods used to estimate the utility's actual future avoided costs. An example of an inherently uncertain input used to estimate avoided costs is the projections of fuel costs (e.g. $/MMBtu of natural gas) of the utility's resources.

Q. For the benefit of electric consumers, where within the "zone of reasonableness" should QF rates be set?

A. Rates for QF resources, like the rate design for any other electricity tariff, must follow the principles of ratemaking; more specifically, QF rates must be just and reasonable. In Addition, Act 62 requires that the Commission must establish avoided cost rates that are "just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and [] strive to reduce the risk placed on the using and consuming public."

QF rates must be developed based on credible analysis of the utility's avoided costs within the bounds of uncertain inputs and methods, which I define above as the "zone of reasonableness." Within this "zone of reasonableness," leaning toward higher rates could marginally increase customer costs; however these costs are transparent, stable, and tied to performance (i.e., the output of a given QF's resources). Moreover, to the extent higher rates encourage QF development and deployment, they can yield other benefits beyond avoided utility costs. In contrast, leaning toward lower rates within the "zone of reasonableness" could have significant negative consequences in addition to undercompensating QF resources.

Q. Please describe the risks of compensating QF resources below the costs they enable the utility to avoid (i.e., QF rates leaning toward the lower end, or outside, of the "zone of reasonableness").

A. The clearest risk of QF rates approved below a utility's avoided costs is stifled competition in the market. In addition to the lost competition to utility resources that drives down utility resource costs, the stifled competition of a QF market can be detrimental to the diversity of the utility's resource mix.

A less commonly understood but equally significant risk of low QF rates is the loss of a hedge against cost overruns associated with large traditional resource procurements. Given the fact that DESC uses the Difference in Revenue Requirement (DRR) method to derive their avoided capacity cost rates for QF resources, QF capacity rates are partly based on the overall capital costs of new generation resources. Per DESC's methodology, the overnight capital cost of these new generators does not account for the risk of potential cost overruns due to development.[3] As such, QF rates that err towards the low end of the "zone of reasonableness" creates an asymmetric risk borne on the shoulders of electric consumers. In other words, low QF rates can saddle electric consumers with both the cost overrun risk of the utility's avoided resource and the risk of lost diversity in the utility's resource mix, which could lead to more volatile operational costs and system resiliency issues. Low avoided cost rates do facilitate the utility's ability to build another resource into its rate base, adding to shareholder profits.

Q. What are the risks of lumpy, capital-intensive investments in large generation resources such as a gas combustion turbine?

A. Due to major technological innovations in the electricity sector the dynamics of energy markets across the world are changing incredibly fast. As the cost curves of emergent technologies decline at a rapid rate, the risk of stranded costs for 20- to 40-year capital-intensive traditional infrastructure investments increases at a similar rate. Below are some trends, which are not hypothetical, indicating how these market dynamics are unfolding across the United States:

- Coal plants that are still on PacifiCorp's balance sheet (and in its rate base) are

[3] Based on review of ORS AIR 2-1, ORS AIR 2-2, and the supplemental response to ORS initial AIR 1-3.

operating uneconomically, i.e., losing the utility money.[4] Studies indicate that replacing most of those plants with new wind power purchase agreements would be cheaper for the utility, even without taking the plants out of its rate base.[5]

- Utility Commissions across the country are rejecting utility plans to build new gas plants because smaller and cleaner alternatives could be cheaper.
    - The Arizona Corporation Commission instituted a moratorium on new gas plants after rejecting the IRP filed by the state's investor-owned utilities.[6]
    - The Oregon Public Utility Commission rejected Portland General Electric's (PGE) initial IRP indicating a need to possibly build one or two new gas plants. PGE found the gas plants could be avoided with small-scale solar qualifying facilities and a renewed hydro contract.[7]
    - The Indiana Utility Regulatory Commission rejected an 850 MW gas plant proposed by the investor-owned utility, Vectren, and directed the utility to

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[4] PacifiCorp, *2019 Integrated Resource Plan Public Input Meeting*, 2018 December 3-4: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_December_3-4_2018_PIM.pdf

[5] Energy Strategies, *PacifiCorp Coal Unit Valuation Study: A Unit-by-Unit Cost Analysis of PacifiCorp's Coal-Fired Generation Fleet*, 2018 June 20: https://www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf

[6] Utility Dive, *Arizona Regulators Move to Place Gas Plant Moratorium on Utilities*, 2018 March 15: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/

[7] Portland Business Journal, *PUC gives Portland General Electric another chance on new renewables*, 2017 August 8: https://www.bizjournals.com/portland/news/2017/08/08/puc-gives-portland-general-electric-another-chance.html

evaluate alternatives to large, centralized resources.[8]

- Utility-scale solar-paired energy storage resources are "solidly competitive" with natural gas combined cycle plants across the U.S.[9]
- The Public Service Company of Colorado selected the winning bids from its 2017 all-source solicitation to replace retiring coal plants. The selected portfolio included 1,131 MW of wind, 707 MW of solar PV, and 275 MW of battery storage and not a single MW of new natural gas.[10]

Q. Can you detail how smaller generation resources like solar QFs are less financially risky relative to traditional large-scale generation resources like gas?

A. A recent study examined 39 solar projects and found that 16 of those projects experienced cost overruns, which were on-average only 1.3 percent over their projections.[11] In contrast, of the 36 thermal plants examined in the same study, 24 of the plants overran their cost projections by nearly 13% on-average. In other words, the solar projects are significantly less financially risky than the traditional thermal resources, validating one of the study's hypotheses that decentralized and modular projects experience few and small cost

[8] Utility Dive, *Indiana regulators reject Vectren gas plant over stranded asset concerns*, 2019 April 25: https://www.utilitydive.com/news/indiana-regulators-reject-vectren-gas-plant-over-stranded-asset-concerns/553456/

[9] Fluence, *Beyond Peaker Replacement: Solar+Storage Finds a New Job*, 2019 April 18: https://blog.fluenceenergy.com/fluence-energy-storage-solar-storage-mid-merit-utility-scale-asset

[10] Greentech Media, *Xcel to Replace 2 Colorado Coal Units With Renewables and Storage*, 2018 August 29: https://www.greentechmedia.com/articles/read/xcel-retire-coal-renewable-energy-storage

[11] B.K. Sovacool et al., *An international comparative assessment of construction cost overruns for electricity infrastructure*, Energy Research & Social Science 3 (2014) 152–160. Please see Table 1 on page 154.

overruns.[12]

In addition, a key benefit of QF resources is that with PURPA-based contracts, the developers not ratepayers bear any cost overrun risk.

Q. Are there examples of cost overruns from non-QF resources that have negatively impacted South Carolina customers?

A. Yes. As has been widely reported, the construction of Units 2 and 3 at the VC Summer nuclear plant were cancelled in 2017, in part due to cost overruns during the construction process. Despite the project's cancellation, electric customers still paid over $2 billion for the uncompleted reactors.[13] This example highlights the potential risks involved with conventional generation resources. In stark contrast, the payment to QFs is performance-based and customers are not subject to any risk of construction cost overruns.

Q. Please describe the benefits of QF resources beyond enabling the utility to avoid certain costs.

A. Leaning towards a slightly higher value for QF rates within the zone of reasonableness can be justified by the following benefits not necessarily captured in the avoided cost frameworks, such as:

- Option value, which can enable to the utility to plan their system in a more cost-effective manner by matching generation resource needs to demand on a more

[12] B.K. Sovacool et al., *Risk, innovation, electricity infrastructure and construction cost overruns: Testing six hypotheses*, Energy 74 (2014) 906-917.
[13] The Post and Courier, *S.C. utilities knew of big problems 6 months into nuclear project but didn't tell customers*, 2018 March 5: https://www.postandcourier.com/business/s-c-utilities-knew-of-big-problems-months-into-nuclear/article_0340cb3a-208e-11e8-8b74-971e7fda2095.html

precise basis;

- A hedge against risk of cost overruns of large plants;
- A long-term (i.e. 10-year) hedge against risk of fuel price uncertainty;
- Increased competition will drive prices down for customers over time;
- Support of state public policy goals such as encouraging renewable energy and local resources;
- Environmental benefits from reduced emissions and coal ash;

Q. Please describe how QF resources can provide optionality to the utility and why the option value is beneficial.

A. Investments in traditional generation resources are capital-intensive and lumpy, i.e., the investments do not occur evenly over the effective useful life of the resource but instead happen in large outlays during small intervals over the effective useful life. Committing to a capital-intensive investment causes a significant loss of flexibility that smaller, more prudent investments in the electric system such as QF resources provide by enabling the utility to adapt to future changes and leverage the rapidly decreasing costs of renewables, energy storage, and other emergent energy technologies. FERC's PURPA regulations specifically recognize this benefit of QFs, directing utilities commissions to take into account in calculating avoided cost rates "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities." 18 C.F.R. § 292.304(e)(2)(vii).

Q. What are the potential cost impacts to DESC's customers if your proposed QF rates

are adopted instead of the lower rates proposed by DESC?

A. I believe the impacts on ratepayers will be relatively small. For example, our proposed QF rates do not include DESC's proposed integration charge of $4.14/MWh for DESC. Even under the most extreme solar deployment case that DESC considered (i.e. the 1,044 MW All Solar scenario), we estimate this will result in a change in total revenue requirement of <1%. The table below illustrates this:

Table 1. Illustration of impact to revenue requirements from inclusion/exclusion of integration charge.

	DESC
MW of Solar	1044
Percent assumed to be deployed in SC	100%
Capacity Factor (based on a SAT system located in SC)	18.90%
MWh output	1,728,488
DESC's Proposed Integration Charge ($/MWh)	$4.14
Total Integration Charge Collected from SC QFs (millions)	$7.2
Estimated Annual Revenue Requirement ($millions)[14]	$2,571
Integration Charge as % of total Rev. Req.	0.3%

Thus, even in the most extreme case, the inclusion of DESC's proposed integration charge will potentially save SC customers <1% on their electric bills. In contrast, eliminating the integration charge would yield a negligible bill impact, while providing end-use customers with stable energy costs from QF resources over the next 10 years that are not subject to

[14] Based on DESC's rate increase in docket numbers D-2015-160-E.

fluctuations in volatile commodity costs.

V. IMPORTANCE OF TECHNOLOGY-APPROPRIATE AVOIDED COST RATES

Q. How has DESC differentiated its proposed avoided cost rates among QF technologies?

A. DESC has proposed the following distinct rate methodologies:

1. Short-run avoided costs for solar and non-solar QFs up to 100 kW (PR-1)
2. Long-run avoided costs for solar and non-solar QFs up to 2 MW (PR-Standard Offer)
3. Long-run avoided cost for solar QFs with storage charged by solar

For QFs larger than 2 MW, the company will negotiate avoided cost contracts, calculating avoided capacity and avoided energy under the same broad methodology, but with "unit specific data to calculate avoided costs."[15]

Q. Do you believe DESC's approach of using different rate methodologies for solar and solar-plus-storage is appropriate?

A. No. This resource-specific approach raises significant concern about the ability of separate rates to properly represent the full suite of QF technological possibilities within the categories of "solar" and "solar-plus-storage." Singling out these resource categories and computing pre-determined avoided cost rates suggests that they each have rigid technological and performance specifications when in fact both "solar" and "solar-plus-

[15] Direct Testimony and Exhibit of James W. Neely, p.15.

storage" cannot be generalized as such.

Solar technology, for example, is constantly evolving, with tracking systems, west-facing panels, and different inverter ratios enabling more flexible output than traditionally-modeled fixed systems. Strategic curtailment can also facilitate a more dispatchable resource profile and reduce integration costs.

Adding storage to the mix provides nearly limitless possibilities in terms of system size, duration, and dispatch instructions. Moreover, storage can be added to existing solar facilities at a later date. Setting a single avoided cost rate for solar, or solar-plus-storage, as DESC has done, obscures these complexities and may dissuade future solar QFs from pursuing technological options that could allow these systems to increase their value to DESC's system.

Q. What to you recommend as an alternative?

A. I suggest that a single QF rate be determined (for projects up to 2 MW) that reflects the value to DESC's system regardless of the underlying technology. This could be similar to the non-solar QF rate that DESC has proposed, but made available to all technologies. I believe such a "technology-neutral" rate would provide a better price signal to prospective solar and solar-plus-storage generators to target energy and capacity delivery during the times they benefit customers most. This approach is especially well-suited for solar plus storage due to the fact that storage can be dispatched at any time and is thus closer in nature to a non-solar QF that can also dispatch at any time.

Q. Is there precedent for this type of approach?

A. Yes. This is not an unusual approach. In fact, in the concurrent South Carolina avoided cost dockets of Duke Energy Progress and Duke Energy Carolinas, the Companies have proposed technology-neutral standard offer avoided energy rates[16].

Q. If a "technology-neutral" rate is not adopted, what changes must be made to ensure the technology-specific QF rates are fair?

A. To ensure all technology options are fully represented, DESC would need to update and rerun its PROSYM model for every possible permutation of solar and solar-plus-storage, as well as every possible dispatch schedule. Moreover, if storage is added to the system during the contract term, there should be an option to revise the solar rate to the non-solar rate, given that storage is fully dispatchable. For negotiated PPAs above 2 MW, I recommend that DESC again configure its model to account for more flexible solar technology specifications, and make these components part of its unit specific data. Additionally, systems should have the opportunity to revise their rate if storage is added in later years. Solar-with-storage QFs should be treated as a non-solar resource profile based on the nameplate capacity of the solar installation.

[16] Docket 2019-185-E and Docket 2019-186-E. "Direct Testimony of Glen A. Snider on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC"

VI. AVOIDED COST ENERGY RATES

Q. As a general matter, are Dominion's avoided cost filings "reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified," as required by Act 62?

A. No, they are not. As discussed below, there are several aspects of DESC's avoided cost calculations and methodologies that are obscure and unexplained, both in Dominion's initial cost filings and in discovery responses. Dominion's filings are far less transparent than Duke's filings, which themselves were not models of clarity. As a result, there may be additional problems with methodologies and assumptions beyond the issues identified in my testimony below. Certainly it would be impossible to independently "verify" the reasonableness of Dominion's proposed rates based on the information that has been provided by the company. The issues on which there is a meaningful lack of transparency include (but are not limited to) the rationale for selection of peak hours and peak seasons as well as hourly avoided cost data and marginal cost data for the base and change case in DRR analysis.

A. Critique of Methodology, Inputs, and Assumptions

Q. Please describe the methodology DESC has used to calculate avoided energy cost rates as you understand it.

A. DESC estimates the hourly cost of electricity production on its system for each hour over the next ten years. This estimation is done through the use of a production cost simulation, PROSYM, which considers many variables including DESC's existing and future generation resources, transmission constraints, and projections regarding commodity fuel costs. Production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost. The model is run for both a "Base Case" reflecting the status quo, and a "Change Case" reflecting the addition of a zero-cost 100 MW QF generator. The hourly energy cost (in $) and hourly energy production (in MWh) is determined for each case and the differences are calculated for each hour. These differences are then combined to develop average differences for each of four time periods (Peak Season Peak, Peak Season Off-Peak, Off-Peak Season Peak, and Off-Peak Season Off-Peak) within each year. Average avoided energy cost values are then computed by dividing total cost ($) by total production (MWh) for each time period within each year. For each of the four different pricing periods, the annual average values are levelized over two different time ranges: 2020-2024 and 2025-2029.

Q. Do you have any concerns that certain assumptions or methodologies may be biased or incorrect in DESC's avoided energy cost calculations?

A. Yes, I have several concerns, as follows:

1. DESC's potentially biased selection of its four proposed pricing periods and its impact on the resulting avoided cost rates.
2. DESC inaccurate treatment of integration costs in its proposed avoided energy cost rates for new solar QFs.
3. Multiple limitations to DESC's treatment of solar with storage, including a) inappropriate treatment of storage dispatch capabilities for the purposes of

calculating energy rates, b) overly restrictive storage sizing requirements, and c) overly restrictive utility control requirements.

4. General concerns about DESC's modeling approach as it relates to energy imports and exports, and the underlying resource assumptions.

i. Selection of Pricing Periods and Resulting Energy Rates

Q. How does DESC divide its avoided energy cost pricing periods?

A. DESC has created four time-of-delivery periods, each with its own avoided energy cost. The prices have been separately calculated for 2020-2024 and 2025-2029, yielding eight total avoided energy values as shown in the table below.

STANDARD OFFER RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/MWh)

Time Period	Peak Season Peak Hours ($/MWh)	Peak Season Off-Peak Hours ($/MWh)	Off-Peak Season Peak Hours ($/MWh)	Off-Peak Season Off-Peak Hours ($/MWh)
2020-2024	32.80	27.97	33.01	30.73
2025-2029	38.79	31.66	41.91	35.19

The periods are defined both seasonally and by time of day, with the "Peak Season" corresponding with the summer months of June through September, and the "Off-Peak Season" corresponding to the non-summer months of October through April. DESC's proposed peak season and peak hours are highlighted in yellow below:

Hour beginning:	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*
June - Sept																								
Oct & May																								
Nov - Apr																								

Q. What are your concerns related to the selection of the avoided energy cost periods?

A. DESC's testimony does not explain how the peak hours or peak seasons were chosen. I am concerned that the proposed time periods selections (or underlying modeling approach) may be biased against solar QFs.

Q. What leads you to believe that the selection of the time periods, or the underlying modeling approach, may be biased against solar QFs?

As shown in the table above, DESC's calculated rates are higher during the winter "Off Peak Season" months, and lower during the summer "Peak Season" months when solar resources are more abundant. Not only does this result appear to disfavor solar QFs, but it is also counterintuitive.

Q. Why are higher Off-Peak Season rates counterintuitive?

A. One would expect higher avoided energy cost rates to coincide with higher-cost hours of the year, which would in turn correspond with higher hourly load, more expensive generator dispatch, and a steeper energy supply curve. In fact, an analysis of DESC's recent load trends indicates average hourly summer load that is distinctly higher than winter load over the last two years; in fact, the summer average exceeds the winter average in almost every hour.

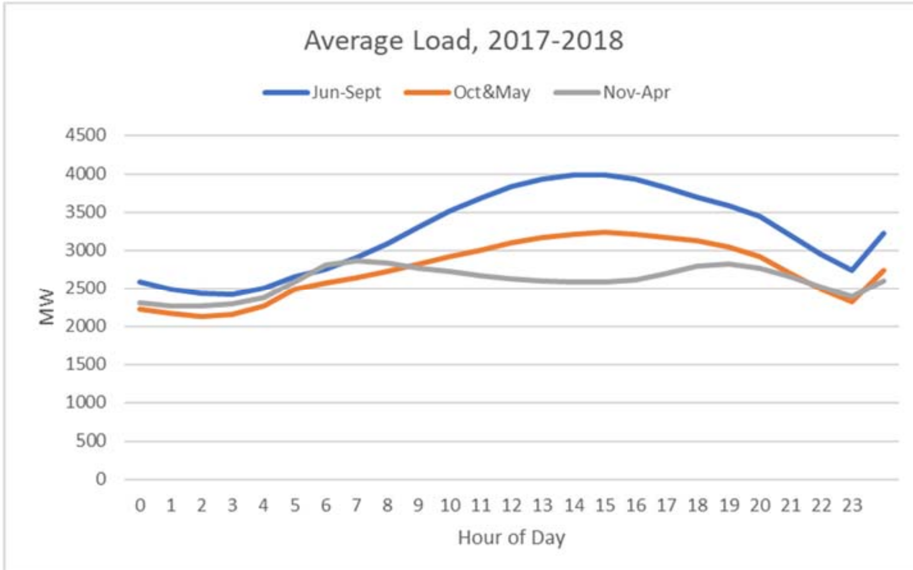

Figure 1. Average Hourly Load in DESC (formerly SCE&G) in 2017 and 2018[17]

Even under a hypothetical scenario with higher levels of solar penetration, (e.g. when ~1,000 MW of solar is added, as DESC has anticipated), net summer demand continues to exceed net winter demand in almost all hours.

[17] S&P Global Market Intelligence. "Historical Loads" for South Carolina Electric & Gas Co. in 2017 and 2018. https://platform.mi.spglobal.com/web/client?auth=inherit#industry/e_analytics_hourly.

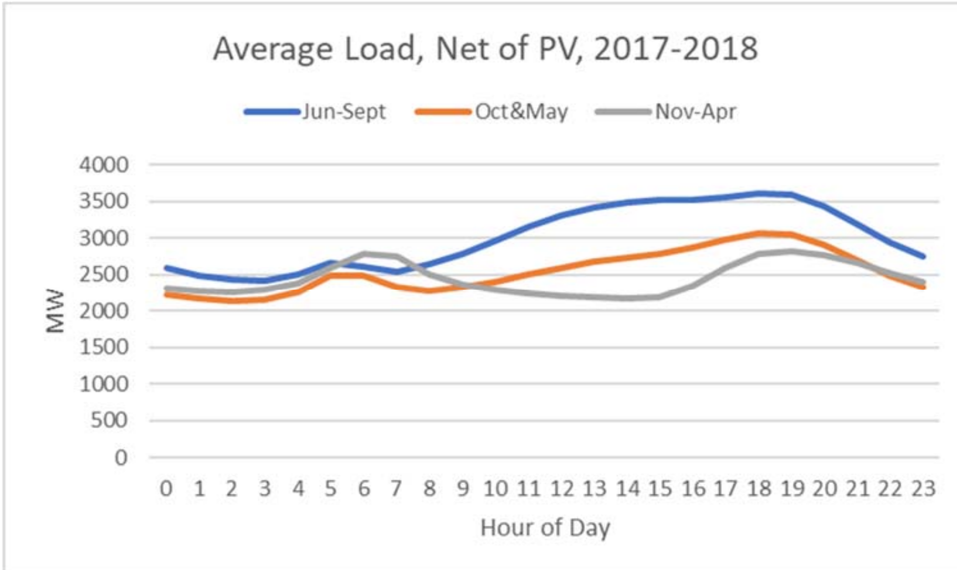

Figure 2. Average Hourly Load in DESC, Net of Anticipated Solar PV[18]

Despite the clear fact that DESC's demand is significantly higher (on average) during the summer months, DESC's proposed non-summer rates exceed its summer rates by 1-11%.

Q. Have you had the opportunity to examine the underlying hourly data that may shed more light on these trends?

A. No. Unfortunately DESC has provided neither hourly avoided cost data, nor hourly marginal cost data for both the base case and change case. Without this data it is impossible for me to assess the reasonableness of DESC's modeling results, or to recommend alternative time period selections. In any case, there appears to be a clear contradiction between DESC's historically higher summer load and its proposed lower summer avoided

[18] Representative solar output profile obtained from PV Watts, for a 1-Axis Tracking DC system in Columbia, SC

energy cost rates. This leads me to be skeptical of the overall modeling approach.

Q. What do you recommend to resolve this issue?

A. First, I suggest that more information be provided on DESC's production cost model to understand the patterns driving this disparity. If the higher winter avoided energy costs are found to be driven by any inappropriate or artificially constraining inputs, the model should be rerun with these inputs corrected. Second, DESC should be required to rerun its model to yield avoided costs results for each of 8760 hours, without pre-emptively aggregating the results into DESC-selected time periods.[19] This would allow stakeholders to more fully examine the model results and the modeling choices that DESC has made. Moreover, this would be consistent with the approach taken by other utilities in South Carolina including Duke.

Q. Do you think this model rerun can be done in a timely manner?

A. Yes. In fact, it is my understanding that DESC recently reran its model well after its direct testimony was filed in response to questions asked by another party in this case. This model rerun produced a revised set of avoided cost rates that were included as part of DESC's amended testimony filed one business day before this testimony was due. As such, it certainly seems plausible for DESC to conduct another model rerun in a similar manner.

Q. Have you had the opportunity to examine the underlying hourly data that may shed more light on these trends?

[19] Given that DESC re-ran its models to produce amended testimony and exhibits on September 20 (the last business day before SCSBA's deadline for prefiled testimony), it appears that the company is entirely capable of performing additional model runs on a relatively short turnaround.

A. No. Unfortunately DESC has not provided hourly avoided cost data. Without this data it is impossible for me to assess the reasonableness of DESC's modeling results, or to recommend alternative time period selections. DESC did provide some updated marginal cost data that I am still reviewing (DESC provided this data one business day prior to this testimony's deadline).

ii. Inclusion of Integration Charges in Avoided Energy Cost Rates

Q. Does DESC seek to impose a Variable Integration Charge (VIC) on existing QFs?

A. Yes. DESC proposes a VIC be applied retroactively on existing QFs based upon its calculation of integration costs in Exhibit No. MWT-2.

Q. In addition to existing QFs, does DESC also seek to impose variable integration costs on future QFs?

A. Yes.

Q. Does DESC propose to apply the same VIC (as computed in Exhibit MWT-2) to future QFs as it applies to existing QFs?

A. No. Instead of a separate Variable Integration Charge (VIC), DESC has proposed to incorporate the supposed integration costs of future solar QFs directly into the avoided energy cost rate. As stated in Neely's testimony, "The increase in operating reserves is now part of the model and is reflected in our estimated avoided energy costs."[20]

Q. In either of the two cases – i.e. 1) the VIC for existing QFs and 2) the integration costs embedded in energy rates for future QFs -- do you think it is appropriate to impose

[20] Direct Testimony of James W. Neely, at 10.

integration costs on QFs at this time and at the level proposed?

A. No. Not only is it premature to impose integration costs, but I believe that in both cases the proposed levels of integration costs are far too high as a result of major flaws in DESC's analysis. I will address my concerns with both forms of proposed integration costs later in my testimony (See Section VIII on Integration Costs).

iii. <u>Avoided Energy Costs for Solar with Storage</u>

Q. Does DESC propose avoided cost rates for solar paired with energy storage?

A. Yes. DESC proposes both avoided energy cost rates and avoided capacity cost rates for solar with storage.

Q. What are your concerns with DESC's proposed avoided energy costs for solar with storage?

A. I have several concerns regarding DESC's proposed treatment of solar-plus-storage and the associated avoided energy cost rates:

a) <u>Failure to Account for Flexible Storage Dispatch.</u>

Q. What avoided energy cost rates has DESC proposed for solar plus storage and how do these compare to standalone solar?

A. As illustrated below, DESC's pre-specified avoided energy rates for solar plus storage are *identical* to the avoided energy rates for solar standard offer systems.

STANDARD OFFER RATE: AVOIDED ENERGY COST
Solar QFs ($/MWh)

Time Period	Annual ($/MWh)
2020-2024	16.76
2025-2029	15.66

AVOIDED COST
SOLAR WITH STORAGE

Time Period	Annual ($/MWh)	Annual ($/kWh)	Monthly ($/kW)
2020-2024	16.76	0.01676	3.17
2025-2029	15.66	0.01566	3.17

Q. What does this equivalence suggest to you regarding DESC's treatment of solar plus storage when calculating avoided energy cost rates?

A. This equivalence implies that in its modeling, DESC did not make any adjustments to the QF resource output to account for the ability of storage to dispatch energy at different times than a standalone solar resource. For example, during winter months, the storage could charge from solar during the midday off-peak period and discharge during the subsequent on-peak period during the evening or following morning. Given the higher value of the energy output during peak times, a solar plus storage resource dispatching in this fashion should be awarded an avoided energy cost rate that is substantially different than a standalone solar resource. In fact, the non-solar QF rate would likely be more appropriate for a solar plus storage resources.

Q. What other differences between standalone solar and solar plus storage are not reflected in DESC's proposed energy rates?

A. Storage can help to mitigate solar integration costs by reducing the intermittency of solar output. However, since the energy rates are the same between the two QF types, DESC has apparently ignored this capability and maintained the same integration costs in the solar-plus-storage rate. This approach is unacceptable, given the unique features of energy storage systems. As I mentioned in my earlier section on technology-appropriate rates, I recommend that DESC assign solar-with-storage QFs the same rate and methodology as non-solar QFs, given the dispatchability of storage resources.

b) Arbitrary system size limitations.

Q. What requirements has DESC proposed for storage systems paired with solar?

A. DESC has required that any storage system must "initially have a minimum capacity of 15 MW-AC and have the ability to deliver its maximum capacity for four consecutive hours when fully charged"[21]. Not only is this size limit arbitrary, but it is in sharp contrast to the requirements for other QF resources, which may even be smaller than 100 kW.

Q. What rationale does DESC provide for this arbitrary limit of 15 MW?

A. DESC contends that smaller storage systems would experience a greater "possibility for operational burdens during critical periods."[22]

Q. Does this make sense to you?

A. No. I can't think of any fundamental reason why a smaller storage system would inherently be more operationally burdened than a larger system during critical periods.

[21] Direct Testimony and Exhibit of James W. Neely, p.17.
[22] Response to SBA IR 2-19.

Q. What do you recommend instead?

A. Instead of the proposed storage MW size limits, DESC should impose no minimums, and should use the inverter rating at the point of interconnection to determine the solar-with-storage system's eligibility for PR-1, standard offer, or negotiated PPA avoided cost rates.

Q. What about the 4-hour duration requirement?

A. Regarding duration, I recognize that duration is a critical factor in terms of assessing the dependable capacity of a storage resource and that 4-hours is a commonly used duration for qualifying capacity resources in many markets. However, I still believe that this may be an overly burdensome restriction due to the fact that a) some capacity contribution is still realized even from shorter durations of output, b) batteries can be dispatched to provide four hours of output at a level less than their maximum rated capacity, c) the combination of solar and storage could provide 4 hours of continuous output even if the battery is of a shorter duration. Recognizing these factors, I think it makes more sense to adopt a PPA protocol similar to that recently proposed in North Carolina.

Q. Can you describe this protocol?

A. Yes. The protocol attempts to balance the capabilities and limitations of storage, with a desire to maximize output during critical peak hours for reliability. The specific language of the protocol is as follows:

> For all (winter and summer) months/days with capacity rate hours ("Capacity Hours"), the Seller shall distribute any discharge of the Facility (the combined output of the generator and the storage device) in a manner that levelizes (holds

constant) the output of the Facility (the combined output of the generator and the storage device) at the highest practical level over the duration of the Capacity Hours of such calendar day, except as limited by ramp rate criteria, inverter capability, and the Facility's Contract Capacity as specified in the Agreement.

c) <u>Requirement that DESC control the storage system.</u>

Q. What requirements has DESC proposed regarding its ability to control storage systems that are paired with solar?

A. Per its filed testimony, "DESC will control the dispatch of the storage"[23]. This requirement is unnecessarily restrictive and introduces significant uncertainty as to the value that storage developers and owners can expect from their QF investment. Because DESC does not specify exactly how it will dispatch the resource, developers cannot assume that DESC will operate the storage in a way that optimizes its economic value. In fact, there is no assurance that DESC will choose to use the storage system at all. Without this assurance, developers are unlikely to pursue any solar-with-storage QFs in South Carolina.

Q. What are the implications of this for relying on storage as a capacity resource?

A. It is understandable that DESC would like to count on the availability of storage during contingency events. However, there may be alternative approaches to requiring DESC to have full control and dispatch at all times. For example, DESC could take a similar approach to Duke in which the resource must maintain a consistent level of output during

[23] Direct Testimony and Exhibit of James W. Neely, p.17.

predefined peak hours windows in accordance with the PPA protocol described above. Alternatively, DESC could provide a "bonus" payment to QFs that agree be dispatched during certain times when called upon with advanced notice. On this limited basis, DESC may exert control over the system, while leaving system dispatch up to the developer or owner the rest of the time.

iv. Other general modeling concerns:

a) Treatment of imports and exports

Q. What are your concerns about DESC's avoided energy cost model with respect to imports and exports?

A. DESC's model appears to have very limited consideration of energy imports and exports. As DESC explained in its Amended Response to SBA RFP 1-2c, "The Company does not use forecasts for power and capacity in its production cost modeling or other modeling used in support of any Avoided Cost Methodology or Calculation in this docket. Rather, the Company provides the model with the ability to call on purchases of energy and/or capacity if needed." This may have a meaningful impact on the avoided energy cost results.

b) IRP assumptions

Q. What are your concerns about DESC's resource plan and how it might affect avoided cost rates?

A. DESC develops its avoided energy costs by modeling generation forecasts based on a chosen future resource plan. The underlying study DESC used to select the resource plan[24],

[24] As presented in Direct Testimony and Exhibit of James W. Neely, Exhibit No.___JWN-1.

however, has been built around outdated assumptions about the cost of solar systems and battery energy storage. Therefore, the results of the resource plan study could be incorrect and in turn, so too could be the results of DESC's avoided energy cost modeling.

v. __Environmental Costs__

Q. Are there environmental harms and associated environmental costs that QFs mitigate?

A. Yes. While DESC's avoided energy cost rates include avoided variable environmental compliance costs such as sulfur dioxide and nitrogen oxide,[25] they fail to include costs associated with coal combustion residuals (CCR) that could be mitigated by qualifying facilities.

Q. Does DESC maintain ash storage ponds that would incur the costs of maintenance and regulation?

A. Yes. Per SCE&G's[26] 2019 Integrated Resource Plan, the company maintains multiple open and closed ash storage ponds, along with CCR landfills[27].

Q. Do you have any examples of coal ash costs in South Carolina?

A. Yes. Under Docket No. 2018-319-E, Duke Energy Progress recently requested recovery of

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[25] Direct Testimony and Exhibits of Allen W. Rooks. P.24. (Exhibit No.____AWR-5))
[26] SCE&G is now DESC.
[27] South Carolina Electric & Gas Company 2019 Integrated Resource Plan. http://www.energy.sc.gov/files/SCE&G%202019%20IRP.pdf. p.33.

$635,040,092[28] in coal ash expenses, while Duke Energy Carolinas requested $876,206,294[29]. This $1.5 billion in proposed ratepayer costs reflects the significant liability of continued coal plant utilization. QF resources such as solar PV involve none of these prospective costs. To the extent that solar QFs displace coal generation, they can play a role in minimizing future coal ash expenditures borne by ratepayers.

Q. Were reduced coal ash costs included in DESC's proposed avoided energy costs for QFs?

A. Not as far as I can tell based on the information provided by DESC. This is especially problematic given that DESC stated in its IRP that it anticipates increasing deployment of coal-fired generation units to follow load.

B. Calculation of Alternative AC Energy Rates for DESC

Q. Do you recommend alternative avoided energy cost rates for DESC at this point in time?

A. More information is needed from DESC to fully develop an alternative. As explained above, DESC has not provided sufficient information regarding the hourly avoided cost results that would allow for an alternative to be developed. Moreover, DESC appears unwilling to rerun any of its models with different inputs (despite requests to do so),[30] even

[28] Direct Testimony and Exhibits of Dan J. Wittliff, P.E., BCEE on behalf of the South Carolina Office of Regulatory Staff Docket No. 2018-318-E in Re: Application of DESC Energy Progress, LLC for Adjustment in Electric Rate Scheduled and Tariffs and Request for an Accounting Order

[29] Direct Testimony and Exhibits of Dan J. Wittliff, P.E., BCEE on behalf of the South Carolina Office of Regulatory Staff Docket No. 2018-318-E in Re: Application of DESC Energy Carolinas, LLC for Adjustment in Electric Rate Scheduled and Tariffs and Request for an Accounting Order

[30] For example, see response to SBA Int. 2-22a.

though it is clearly capable of doing so in a timely manner.

Q. Are there other potential changes you want to propose in calculating an alternative rate?

A. Yes. One minor change I would suggest is related to the way DESC levelizes its avoided energy cost rates across yearly periods.

Q. What alternative do you recommend to the time periods DESC has selected for setting its avoided energy costs?

A. As described above, DESC calculates its avoided energy costs across ten years but divides those into two 5-year periods for pricing purposes. This approach results in energy rates that are lower during the first five years and higher during the second five. I recommend giving QF developers the option to utilize DESC's proposed periods or to select a fixed 10-year levelized price instead. The 10-year price would apply the same methodology that DESC has proposed for levelizing the two five-year periods, including using its weighted average cost of capital (WACC) as the discount rate. This approach should leave the company indifferent to the outcome one way or another, while allowing QF developers, who may face high capital costs, some flexibility as they decide whether higher upfront returns are more important to them than the value of the full contract. The different proposed options for the non-solar standard offer rates are shown below, for comparison.[31]

[31] These rates were calculated using DESC's proposed rates prior to being amended on September 20, 2019. The same concept would apply to the amended rates, though the exact rates provided by Dominion differ.

[redacted]

Table 2. Standard Offer Avoided Energy Costs for Five- and Ten-Year Term Options

VII. <u>AVOIDED COST CAPACITY RATES</u>

A. <u>Critique of Methodology, Inputs and Assumptions</u>

Q. Have you reviewed DESC's proposed approach to calculating avoided capacity costs for the purpose of setting an avoided capacity rate under PURPA?

A. Yes.

Q. Do you believe DESC's proposed method is appropriate?

A. Partially. I believe the general framework (i.e. the Difference in Revenue Requirement method) is sound. However, there are specific assumptions and methodological choices that I believe are incorrect and biased against QFs and solar QFs in particular. These flawed assumptions and methods underestimate the true avoided capacity costs for DESC and the corresponding rates DESC has proposed.

Q. What assumptions or methodologies are you concerned may be incorrect and biased against solar QFs?

A. There are several. Briefly, my concerns about avoided capacity costs relate to the following key assumptions:

- The assumed costs of incremental capacity resources included in DESC's base resource plan including:
    - New peaking power plants
    - Capacity purchase prices
- The assumed capacity value for solar QFs.

I will describe each of these in more detail in my testimony below.

i. Capital Costs of New Generation and Capacity Purchase Prices

Q. Can you describe in general terms how DESC calculated its proposed avoided capacity costs in this proceeding?

A. Yes. DESC used a Difference in Revenue Requirement (DRR) method. Under this method, the fixed cost revenue requirements for DESC's Base Case resource plan was first calculated. Second, a new resource plan (i.e., the Change Case) was determined that included a 100 MW no-cost generation source. This defers certain fixed costs in the Change Case. The new revenue requirements were then computed under the Change Case and the difference between the Base Case and the Change Case were used to determine the avoided capacity costs in \$/kW-yr terms. These costs were then converted to a \$/MWh value by allocating the avoided capacity costs over DESC's determined hours of capacity need, specifically winter morning hours of 6-9 a.m. in December, January, and February.

Q. What fixed costs were included in DESC's Base Case?

A. In its in initial direct testimony DESC stated that "resource scenario #7 is the resource plan used in developing avoided costs and forecasting fuel costs."[32] This resource plan included a new combined cycle plant in 2029, as well as wholesale capacity purchases in years 2022 through 2028.

Q. Did DESC actually use this plan to calculate its avoided cost rate for capacity?

A. No. In its response to SBA IR 2-17 (provided 1 business day before this testimony was due), DESC clarified that it used an "updated resource plan," in which "ICT peaking turbines, instead of combined cycle, was used."

Q. What has DESC's proposal assumed regarding the capital cost of new generation resources in its base resource plan (i.e. the marginal cost of new capacity)?

A. DESC has proposed that the marginal cost of new capacity be based on a peaker unit with an initial capital cost of $697/kW. This is based on the EIA's 2017 Cost and Performance Characteristics of New Generating Technologies Table in their Annual Energy Outlook, considering a regional cost adjustment for the SERC VACAR Region, and an inflation adjustment.

Q. Do you believe DESC's assumed capital cost of a new peaker is incorrect and potentially biased against QFs?

A. Yes. For calculating the avoided capacity costs, DESC has selected the lowest cost available peaking unit included in EIA's predetermined list of potential generation technologies. This does not necessarily correspond to the cost of the peaking unit that DESC would ultimately select to meet future peak demand or provide other services.

[32] Direct Testimony of Neely, Exh. JWN-1, p 8.

Q. What other types of peaking units might be appropriate for DESC to consider in its selection?

A. Recently, there has been a growing trend towards more flexible, aeroderivative types of peakers. For example, in PJM, aeroderivative CTs recently outnumbered conventional frame CTs (DESC's selection) in both project count and capacity. For instance, a recent report on new capacity in PJM noted 12 aeroderivative projects totaling 714 MW versus only 3 frame projects totaling 481 MW.[33]

Moreover, DESC's own proposal in this proceeding suggests that there will be significant future solar integration costs that may lend themselves towards installing more flexible types of peaking unit that can better respond to variable generation in order to mitigate these integration costs. While these flexible types of peaking units are generally more efficient and more responsive to the grid's needs, they are also more expensive in terms of upfront capital costs.

[33] "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date", The Brattle Group, 2018, p. 15.

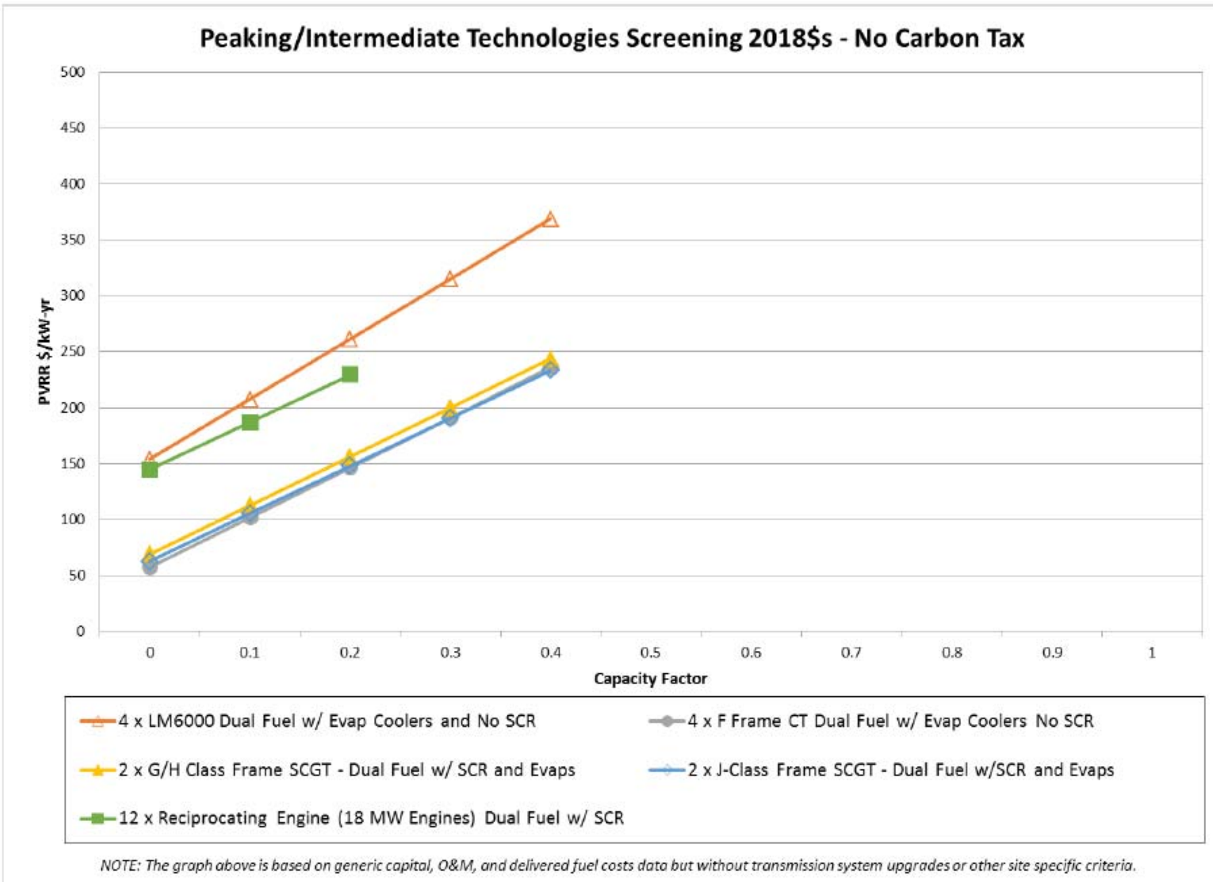

Figure 3. Peaker technology cost screen from Duke's 2018 IRP

For comparison, Duke's 2018 IRP suggested that the fixed costs of an aeroderivative CT (LM6000, 0% capacity factor) was approximately 2-3 times that of an advanced frame CT (see Figure 3 above). This is consistent with cost estimates I have observed from other utilities. For example, in its 2018 IRP Dominion Energy Virginia projected an overnight capital cost of an aeroderivative CT of $1,680/kW.[34]

[34] Dominion Energy Virginia 2018 Integrated Resource Plan, Appendix 5B: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf

Q. What do you recommend instead of using DESC's assumptions for peaker capital costs?

A. Given the recent trends towards more flexible peaker technologies that can meet both peaking and ramping needs, I believe it is appropriate to consider a different initial capital cost than what DESC has proposed. While the EIA cost assumptions are reasonable for a frame CT, they are not reasonable for an aeroderivative CT or internal combustion engine (ICE). Meanwhile, there is sufficient reason to believe that one of these more flexible types of peakers will in fact be the marginal capacity resource due to both market trends and evolving grid needs. As such, I propose a capital cost assumption of $1,178/kW which represents the midpoint of these the two classes of peaker technologies.[35]

Q. What other factors may be underestimated in the avoided capacity cost calculation in DESC's proposal?

A. In addition to the cost of the generation resource itself, DESC also estimates the cost of capacity purchases from other neighboring utilities to avoid a capacity shortfall. DESC forecasts that capacity purchases will be necessary in years [redacted]. In its workpapers labeled "AVOIDED_CAPACITY_-_10_YEAR_ICT_081319_CONFIDENTIAL", DESC discloses that it used a cost estimate of [redacted] to approximate the cost of purchased capacity.

Q. Do you believe DESC's proposed cost for purchased capacity is appropriate? If not,

[35] Based on DESC's estimate of $667/kW and Dominion's estimate of $1680/kW.

what would be an appropriate estimate?

A. No. I believe this cost is relatively low and does not accurately reflect the market value a kW of capacity has in the region DESC serves. By using a low cost estimate, DESC is artificially depressing the avoided capacity cost in the change case; thus, hindering the benefits a QF would receive. A better estimate of purchased capacity costs can be found in Dominion Energy Virginia's 2018 IRP, which includes estimates for PJM's RTO-wide clearing prices for capacity delivery over the following 15 years.[36] This data shows that the potential market valuation of each kW of capacity provided escalates from $31.5/kW-yr in 2020 to $67.3/kW-yr in 2028. These values are more likely to reflect the true cost DESC would incur in order to prevent a capacity shortfall by securing additional capacity through a market transaction.

Q. Would the avoided capacity costs change if DESC were to use your recommendation that considers the cost of an aeroderivative peaker and PJM's forecasted clearing prices for capacity? If so, by how much?

A. Yes. According to DESC, the cost of capacity using their technology and purchase cost estimates is [redacted]. This is based on the data and methods employed by DESC as demonstrated in AVOIDED_CAPACITY_-_10_YEAR_ICT_081319_CONFIDENTIAL. It is relatively straightforward to estimate the cost of capacity considering new generation and purchase price estimates. Using the

[36] Dominion Energy Virginia 2018 Integrated Resource Plan, Appendix 4A: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf

revised CT cost assumption of $1,178/kW and capacity purchase prices that reflect the projected clearing prices of PJM's RTO-wide capacity market, I used the methodology DESC employed in "AVOIDED_CAPACITY_-_10_YEAR_ICT_081319_CONFIDENTIAL" to determine the resulting cost of capacity. These changes result in a capacity cost of [redacted], an increase of [redacted] relative to DESC's original cost estimate.

Q. Are there any other problems with the assumptions in Dominion's resource plan used to compute avoided costs?

A. Yes. It is unclear to me what resource plan was actually used to calculate avoided energy costs. Resource Study (Exhibit JWN-1), suggests that Scenario #7 was used. However, in subsequent responses to SBA discovery requests DESC suggests that an "updated" resource plan was used for the calculation of avoided capacity costs. It is not clear to me if this updated resource plan was also used for the avoided energy cost calculation. If not, then there is a discrepancy between the two components.

Furthermore, the capital costs Dominion used in selecting the base resource plan may be incorrect. For example, in one scenario, Dominion assumes that the capital cost of constructing new battery storage is $2,126/kW ($2017) and the battery storage has no annual operating costs. While it is difficult to evaluate this without knowing more details about the configuration and duration of the battery, I'm concerned that this cost could be too high. For comparison, a report recently published by the Lazard found that total system construction costs for standalone battery storage systems of 4-hour duration in 2018 ranged from $1,140 to $1,814/kW – significantly lower than Dominion's assumptions.[37] It is difficult to say how the use of different cost figures would have affected the overall resource plan (and thus avoided cost rates), but to the extent Dominion's cost assumptions are outdated, it makes it harder to credit the reasonableness of their calculations.

ii. *Capacity Value of Solar QFs*

Q. How does DESC consider the need for new capacity resources in terms of season and time of day?

A. DESC considers its need for future capacity to be primarily in the winter season, even though it has peak load hours in both winter and summer months. DESC's analysis indicates that the highest hours of capacity need occur during two different time periods: 1) the summer afternoon/evening, and 2) winter morning. Capacity value is then allocated to these time periods based on their relative weightings and in turn used for determining the avoided cost rates for capacity.

Q. How has DESC chosen to allocate capacity value based on these two seasonal needs?

A. DESC considers itself a winter-peaking and thus has determined that only generators that can reliably provide capacity during all its peak periods can receive a capacity payment, despite the fact there are a large number of high-load summer hours.

Q. Do you think DESC's approach is appropriate?

A. No. I believe DESC uses an approach that unfairly discounts summer capacity value and

[37] Lazard, *Levelized Cost of Storage Analysis – Version 4.0* (Nov. 2018), at https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

may impose unreasonable costs on ratepayers by using methodology that deviates from the prevalent industry standard.

Q. Hasn't DESC experienced its annual peak load hour during winter in recent years though?

A. Yes, however it is also important to remember that capacity planning should not be seen as a simple binary choice between winter and summer needs. This is especially true in DESC's case where forecasted winter and summer peak loads are extremely close to one another. In reality, probabilities must be taken into account. Since DESC's summer and winter peaks are very close, there is a strong probability that either season will be the peak load hour for the year, even if one is slightly favored.

Q. Can you provide a simple analogy for how probabilities should be taken into account for seasonal capacity value?

A. Yes. This is somewhat akin to betting on a horse race. One strategy might be to put all your money on the front runner since that horse is more likely to win. However, another strategy might be to place a series of smaller bets on the second, third, and fourth ranked horses. Over the long-run the second strategy could have a similar or even greater payout. Diversifying one's "bets" in this way also serves to reduce the overall risk of the investment, as compared to a single large bet on the leading horse. Likewise, for resource planning, one could plan solely for the one peak hour of the year that has the highest probability of an outage (e.g. as DESC claims, this might correspond to January at 7 a.m.). However, this would ignore many other hours of the year that have smaller, but still meaningful probabilities of an outage. Covering these hours could have the same or even greater contribution to reliability from a probabilistic standpoint as addressing the single peak hours.

Q. Does DESC's proposed seasonal allocation factors of 100% winter and 0% summer have a significant effect on solar QF revenues?

A. Yes, very much so. Since very little solar energy is available during the DESC-defined wintertime periods, higher winter allocation factors (and correspondingly lower summer factors) will lead to lower overall revenues for solar QFs. Thus, allocation factors have an outsized impact on the ability for QFs to obtain fair compensation in exchange for the capacity value they provide.

Q. Do you believe the seasonal allocations modeled by DESC may be incorrect and biased against solar QFs?

A. Yes. DESC's estimation of the seasonal allocations are largely based upon a study it conducted to determine the capacity value of solar, "The Capacity Benefit of Solar QFs 2018 Study", presented as Exhibit No. JML-1. The study concludes that DESC is a winter-peaking utility since it experiences considerable load in the early hours (6 am to 9 am) of December, January, and February.[38] Nevertheless, DESC itself provides evidence that suggests it might not be a solely winter-peaking utility. In his direct testimony, Dr. Joseph M. Lynch presents DESC's total internal demand, that is, DESC's gross load, for summer

[38] See Exhibit No. JML-1 and Exhibit No. JML-2.

and winter.[39] Using the data Dr. Lynch presented, I calculated the difference between the summer and winter estimated net peaks. Figure 4. shows that the average difference between the two seasons over the next 19 years is projected to be less than 2%.

Estimated Net Internal Demand (NID) by Season and Difference				
Year	NID Summer	NID Winter	Difference (Summer - Winter)	Difference in %
2019	4639	4749	-110	-2.32
2020	4688	4792	-104	-2.17
2021	4733	4822	-89	-1.85
2022	4772	4860	-88	-1.81
2023	4810	4882	-72	-1.47
2024	4835	4921	-86	-1.75
2025	4874	4963	-89	-1.79
2026	4919	5007	-88	-1.76
2027	4961	5046	-85	-1.68
2028	5003	5085	-82	-1.61
2029	5042	5124	-82	-1.60
2030	5084	5166	-82	-1.59
2031	5125	5268	-143	-2.71
2032	5168	5248	-80	-1.52
2033	5208	5290	-82	-1.55
2034	5250	5329	-79	-1.48
2035	5292	5368	-76	-1.42
2036	5334	5407	-73	-1.35
2037	5375	5448	-73	-1.34
Average difference (%)				-1.73

Figure 4. Estimated Net Internal Demand (NID) by Season and Difference.

This difference is so minimal, even Dr. Lynch acknowledges in his testimony that "the difference could easily reverse with a small change in customer load characteristics."[40]

[39] Direct Testimony of Joseph M. Lynch, Ph.D., p. 13. See Exhibit No. JML-2.
[40] Direct Testimony of Joseph M. Lynch, Ph.D., p. 16.

Seasonal peaks are correlated with factors such as economic development, demand-side management efforts (including demand response), extreme weather events and expected temperatures; considering this, it is conceivable that DESC will not experience a winter peak in many of these future years and thus it should not rely solely on a three-hour period in the winter to determine capacity payments for the entirety of a solar QF's contract. By doing so, DESC is not properly assessing the capacity contributions of QFs, especially of solar QFs since they are inherently less likely to provide output during the early morning winter hours.

Q. Are there other aspects of the Capacity Benefit of Solar QFs 2018 Study that you think could possibly lead to a biased outcome for solar QFs?

A. Yes. I think some of the key assumptions in the study are biased, including the underlying load data.

Q. What are the relevant considerations of the underlying load data as it relates to seasonal capacity value?

A. For its capacity study, DESC employs a single year of load data in order to justify the position that solar resources have no impact on capacity needs. The study does not present historical data to show whether the winter-peaking year of June 2018 to May 2019 was an anomaly or is actually representative of DESC's load patterns based on historical probabilities. In addition, the study includes no consideration of how load, and the resulting allocations might shift over time. It is entirely plausible that load growth and load shapes will shift over the next 10 years. For example, if summer load grows faster than winter load, it will tend to shift the allocation back towards summer hours. However, this possibility is not considered as part of DESC's analysis.

Q. Do DESC's proposed allocations make sense based on historical load data?

A. DESC does not include historical load to justify its seasonal allocation of capacity value. However, it does mention in Exhibit No. JML-2 that, historically, DESC's summer peak demands have always been larger than the winter seasonal peak demands except for the recent past.[41]

Q. In the aggregate, what is the significance of the modeling flaws you describe above?

A. DESC's use of static load forecast assumptions, emphasis on a few hours of extreme winter weather events, and disregard of historical summer peak load hours results in a seasonal allocation weighting that is significantly biased and fails to recognize or incorporate the full capacity value that solar generators provide.

Q. Did DESC consider other methodologies to calculate the capacity value of solar generation resources?

A. Yes. In his testimony, Dr. Lynch mentions that he also performed effective load carrying capacity (ELCC) calculations because "some interest has been expressed in this methodology."[42] The ELCC method provides a means to determine the incremental capacity value of incremental capacity resources, and can be applied to variable resources such as solar PV.

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[41] Exhibit No. JML-2, p. 2.
[42] Direct Testimony of Joseph M. Lynch, Ph.D., p. 9.

Q. Is the ELCC method commonly used in the industry to assess capacity value?

A. Yes. ELCC is a commonly used method to determine capacity value of a generation resource. In fact, most states that have substantial experience with solar PV have turned to an ELCC methodology to evaluate capacity value. This includes California, Arizona, Colorado, Nevada, and others.

Q. How does the ELCC method assess the contribution of solar PV to capacity value (i.e. resource adequacy)?

A. The ELCC measures the amount of additional load that can be met if an incremental generation resource is added, while maintaining the same performance in terms of a target reliability metric. The target metric most frequently used due to its prevalence in system planning is loss-of-load expectation (LOLE). For example, if the LOLE target is 0.1 day per year, and a 100 MW solar PV generator is added, the ELCC determines how much additional load (in MW) can be added while still keeping under the target 0.1 LOLE value.

Q. Is the LOLE metric (which usually underpins the ELCC calculation) a commonly used reliability metric for resource planning?

A. Most definitely. In fact, 14 out of the 21 reliability assessment areas under the jurisdiction of the North American Electric Reliability Corporation (NERC) use LOLE as a target metric (see Figure 5 below). This includes SERC, of which DESC is a part of.

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023)

Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
FRCC	15%[1]	Reliability Criterion	No: Guideline	0.1/Year LOLP	Florida Public Service Commission
MISO	17.1%	Planning Reserve Margin	Yes: Established Annually[2]	0.1/Year LOLE	MISO
MRO-Manitoba Hydro	12%	Reference Margin Level	No	0.1/Year LOLE/LOEE/LOLH/EUE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	11%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
NPCC-Maritimes	20%[3]	Reference Margin Level	No	0.1/Year LOLE	Maritimes Subareas; NPCC
NPCC-New England	16.3–17.2%	Installed Capacity Requirement	Yes: three-year requirement established annually	0.1/Year LOLE	ISO-NE; NPCC Criteria
NPCC-New York	15%	Installed Reserve Margin	Yes: one year requirement; established annually based on full installed capacity values if resources	0.1/Year LOLE	NYSRC; NPCC Criteria
NPCC-Ontario	18–25%	Ontario Reserve Margin Requirement (ORMR)	Yes: established annually for all years	0.1/Year LOLE	IESO; NPCC Criteria
NPCC-Québec	12.6%	Reference Margin Level	No: established Annually	0.1/Year LOLE	Hydro Québec; NPCC Criteria
PJM	15.8–15.9%	IRM	Yes: established Annually for each of three future years	0.1/Year LOLE	PJM Board of Managers; ReliabilityFirst BAL-502-RFC-02 Standard
SERC-E	15%[4]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-N	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SERC-SE	15%	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1/Year LOLE	Reviewed by Member Utilities
SPP	12%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1/Year LOLE	SPP RTO Staff and Stakeholders

Table 3.3: Reference Margin Levels for each Assessment Area (2019–2023) (Continued)					
Assessment Area	Reference Margin Level	Assessment Area Terminology	Requirement?	Methodology	Reviewing or Approving Body
TRE-ERCOT	13.75%	Target Reserve Margin	No	0.1/Year LOLE	ERCOT Board of Directors
WECC-AB	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-BC	10.14–10.42%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-CAMX[1]	12.02–12.35%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-NWPP-US	19.56–19.72%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-RMRG	16.07–16.83%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC
WECC-SRSG	14.07–15.10%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC

Figure 5. Reference Margin Levels and Methodologies for each Assessment Area (2019-2023) [43]

Q. What do you conclude from this regarding solar capacity value?

A. Since LOLE is the most commonly used reliability metric for resource adequacy planning, including for SERC (where DESC resides) it is appropriate to consider the impact to LOLE when assessing the reliability contribution of a given resource.

Q. Did DESC perform its ELCC calculation using LOLE as the target metric?

A. No. Instead DESC used LOLH as its target metric, not LOLE. I believe this could be a potential source of bias against solar since using LOLH could undervalue solar's contribution during certain hours of the year analyzed relative to LOLE. DESC justifies its selection of LOLH as its target reliability metric by stating that an LOLE-based study could

[43] NERC, "2018 Long-Term Reliability Assessment", December 2018, pp. 53-54, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

"hide" or overlook the risk of sudden and extreme load spikes since it summarizes risk for the entire year.[44]

Q. Do you agree?

A. No. LOLE-based studies can be tailored to look at either the peak load of each day of the year (365 hours per year) or all the hours of the year (8,760 hours). The latter could help ensure that no single hour or load spike is overlooked. Furthermore, spikes in demand can occur during summer afternoon peaks just as they could during winter mornings. In fact, this has been the case in several recent years. As such, it is useful to look across the entire year to gain a full perspective on system reliability.

Q. Despite using LOLH as the target metric, what did DESC's ELCC analysis find?

A. DESC obtained an ELCC of 37% for the first 500 MW of solar added. For the second 500 MW the ELCC was 11.8%. DESC then essentially averaged those results and attributed solar an ELCC value of 24%.[45] These results indicate that solar additions up to 1 GW have a capacity value of about 24% of nameplate capacity, or about 240 MW. Thus, according to DESC's own testimony, solar PV has a meaningful, non-zero capacity value.

Q. Why then did DESC choose to assign solar a zero capacity value?

A. According to DESC's testimony: "DESC needs capacity in the winter and solar does not provide capacity on early winter mornings before sunrise when the system peaks."[46]

Q. Is this determination based on any analysis of a solar resource's contribution to the

[44] Direct Testimony of Joseph M. Lynch, Ph.D., p. 25.
[45] Direct Testimony of Joseph M. Lynch, Ph.D., pp. 9-10.
[46] Direct Testimony of Joseph M. Lynch, Ph.D., p 11.

industry-standard reliability metrics just discussed (e.g. LOLE, LOLH, etc.)?

A. I don't believe so. It appears to be based on anecdotal evidence that solar generates less during winter morning hours, which also have a high probability of a spike in demand. However, this does not appear to be based on any probabilistic analysis of historical or projected future load patterns.

Q. Do you think it is appropriate to conclude that solar has no capacity value?

A. No. Solar clearly has overlap with times of peak demand, and thus higher probability of outage. Even if it does not cover all high probability hours, or even the highest probability hour, it still has a meaningful contribution to reducing the overall probability of an outage and thus has capacity value. This is further evidenced by DESC's ELCC calculation. I believe basing the ELCC calculation on an LOLE metric would further solidify this.

Q. Based on the fact that a) solar has a positive capacity value as determined through the ELCC calculation, and b) DESC generally has a significant number of summer peak load hours, do you recommend a different approach to determining avoided capacity costs from solar QFs than what DESC has proposed?

A. Yes. I suggest two potential options for the Commission's consideration. The first option would be to disregard the seasonal allocation used in DESC's application and instead rely on the ELCC value that DESC calculated to determine capacity payments. The second would be to continue using a seasonal allocation methodology but instead adjust the weightings to more accurately reflect DESC's summer peak load hours. Below I describe how each of these options could be calculated, noting that SBA has a preference for the second option due to the fact that it is more consistent with the preferred "technology-neutral" approach, and is also more consistent with the methodology Duke has proposed in its avoided cost proceeding.

B. Alternative AC Capacity Rate Proposal

Q. Given the deficiencies in DESC's proposal, what do you recommend instead?

A. I propose a revised calculation of the avoided capacity rate proposed by DESC. This revision corrects for many of the deficiencies described above. More specifically it includes:

- Updated assumptions regarding the fixed cost of capacity resources.
- An updated approach to the capacity contribution of solar through one of two options:

  Option 1) ELCC Method for Solar QFs

  Option 2) Technology-neutral Seasonal Allocation Method (preferred option)

i. Alternative capacity cost assumptions

Q. Can you reiterate which changes you recommend regarding fixed capacity cost assumptions and why?

A. Yes. The first change relates to the estimation of peaker plant capital costs and capacity purchase costs. This resulted in assumed total overnight costs $1,178/kW consistent with current trends of plant procurement and the use of PJM's forecast for capacity purchases in $/kW-year considering their projected RTO-wide clearing prices.

ii. <u>Alternative capacity value methods</u>

a) <u>Option 1: ELCC Method for Solar QFs</u>

Q. Can you explain your proposed Option 1 for calculating the capacity value of solar QFs, and corresponding avoided capacity rates?

A. Yes. For the first option, which I will call "the ELCC Method", I largely used the same Difference in Revenue Requirement method used by DESC (with updated capacity costs as described above). However, rather than a 100 MW capacity resource addition, I assumed a 24 MW capacity resource addition, which equates to the 24% ELCC value of solar as computed by DESC. Thus, the expansion plan in the Change Case reflects a capacity need deferral of 24 MW. [47] This results in an avoided capacity cost in terms of $/kW-year, where the denominator represents the nameplate capacity of the solar installed (i.e. 100 MW). Under this option, solar QFs would be provided an equivalent avoided capacity cost payment on a monthly or annual basis.

b) <u>Option 2: Technology-neutral Seasonal Allocation Method</u>

Q. Can you explain your proposed Option 2 for calculating the capacity value of QFs and corresponding avoided capacity rates?

A. Yes. For the second option, which I will call the "Technology-Neutral Seasonal Method," I also largely used the same Difference in Revenue Requirements method that DESC used (with updated capacity costs as described above). However, I applied different seasonal

[47] Note that this scales up accordingly, so that a 400 MW addition of solar QFs would equate to a 96 MW deferral.

weightings than DESC for the summer and winter periods rather than DESC's proposed weightings of 100% for winter mornings and 0% summer afternoons. Additionally, I applied a "technology-neutral" approach whereby the resulting rates are applied based on when QF production occurs and its coincidence with the seasonal peak periods, regardless of the underlying technology.

Q. How did you determine the revised seasonal weightings?

A. I calculated the seasonal weightings by examining the expected distribution of the net load during each hour of the year over the next decade. For this analysis I relied on DESC's hourly load forecast for each year that was used in its PROSYM model. I converted this to a net load by assuming a deployment of 1000 MW of solar PV. Thus, similar to an ELCC analysis, this approach takes into account not only the expected load, but also the expected availability of generation.

I then determined the distribution of net load hours within the top 5% (i.e. 95% percentile) during each year. The vast majority of these hours fell within the summer afternoon/evening hours, while a small share fell within winter morning hours. Based on the prevalence of these peak net load hours I assigned a winter peak load period of 6-9 a.m. during the months of Dec-Feb (equivalent to DESC's approach) as well as a summer peak load period of 2-7 p.m. I then determined the seasonal weightings for each year based on the number of peak net load hours within each period and then took the average over all 10 years. The resulting share of summer and winter values within the peak load periods was found to be 25.23% winter mornings and 74.77% summer afternoons. The seasonal weightings were in turn used to calculated avoided capacity cost rates in $/MWh using a similar approach as DESC used in its proposal.

iii. <u>Summary of Proposed Capacity Rates</u>

Q. Can you summarize the resulting avoided capacity cost rates based on these different approaches?

A. Yes. The table below provides a summary of the different options.

Summary of Proposed Alternative Avoided Capacity Rates			
Test Name	**Original**	**Option 1: ELCC Approach**	**Option 2: Seasonal Approach**
Test Description	Original DESC calculation included for reference	Updated cost to reflect aeroderivative ITC and PJM capacity prices. Modified deferred capacity to account for ELCC of 24%	Updated cost to reflect aeroderivative ITC and PJM capacity prices. Modified seasonal allocation to reflect difference in seasonal peaks.
CT Cost ($/kW)	697	1178	
Purchase cost ($/kW)	13.5	Varying prices by year based on the PJM capacity price forecast included in Dominion Energy Virginia's 2018 IRP	
Capacity Value for Rate Calculation (MW)	100	24	100
Cost of capacity ($/kW-year unless indicated otherwise)	19.83	24.00	45.39
Avoided Capacity Rate, Summer ($/MWh)	$0.00	NA	$78.23
Avoided Capacity Rate, Winter ($/MWh)	$73.46	NA	$64.59

Figure 6. Summary of Proposed Alternative Avoided Capacity Rates

Avoided Capacity Rate Desing Pricing Periods																								
Capacity Price Blocks								*Morning*									*Afternoon*							
Hour ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (June - September)																	Summer							
Hour ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter (December - February)								Winter																

Figure 7. Summary of Proposed Alternative Avoided Capacity Rate Design

Q. Would you be open to further revisions of these alternative calculations?

A. Yes.

VIII. <u>INTEGRATION COSTS</u>

Q. Have you reviewed DESC's testimony regarding its proposal to attribute "integration costs" to solar QFs?

A. Yes.

Q. What has DESC proposed regarding integration costs for both existing and future QFs?

A. DESC has proposed two separate approaches for assessing integration costs on solar QFs – one for QFs with existing PPAs and one for future QFs. Solar QFs with certain clauses in their existing PPA terms would be assessed integration costs in the form of a new Variable Integration Charge (VIC). Meanwhile, future solar QFs would be assessed integration costs in the form of a substantially reduced avoided energy cost rate (versus a non-solar QF) that is intended to account for the effects of solar integration costs. Since the second category of integration charge is embedded in DESC's proposed energy rate, I will refer to this second category as the "Embedded Integration Charge" (EIC).

Q. What analysis has DESC provided in support of either of these categories of purported integration costs?

A. In support of the VIC for existing QFs, DESC commissioned Navigant Consulting to conduct a Cost of Variable Integration study, which was included as Exhibit MWT-2 in the Direct Testimony of Witness Tanner. In support of the EIC, DESC conducted its own internal analysis, the details of which were provided on September 20th, 2019 (one business day before this testimony was due), in response to SBA IR 2-14.

Q. Do you have concerns regarding DESC's proposed integration charges and supporting analysis for both existing and future solar QFs?

A. Yes, I have several concerns including the following:

1) I believe it is premature to impose any integration charges on either type of QF until the true costs of integration can be more accurately quantified through an *independent* analysis as contemplated by Act 62.
2) The analysis relied upon by DESC to support the proposed integration costs contain several fundamental flaws that likely exaggerate the projected cost of integration services.
3) There is very little evidence in South Carolina, or in other jurisdictions, that the magnitude of integration costs projected by DESC will materialize any time soon due to incremental solar deployment.

4) DESC's proposal is incomplete since it only considers integration costs imposed by solar QFs and does not consider integration services that could be provided by solar QFs (as required by Act 62).

5) The form of the proposed VIC is linked to a hypothetical model rather than real-world costs and introduces significant uncertainty that unfairly penalizes QF projects.

I will explain each of these in more detail in my testimony below.

A. Assessing a Charge for Integration Costs is Premature.

Q. Please explain why you believe it is premature to impose any form of integration charge now.

A. Upon passage of Act 62, South Carolina statute was amended to include the following language authorizing ORS to conduct an independent study on integration services:

> "Section 58 37 60. (A) The commission and the Office of Regulatory Staff are authorized to initiate an independent study to evaluate the integration of renewable energy and emerging energy technologies into the electric grid for the public interest. An integration study conducted pursuant to this section shall evaluate what is required for electrical utilities to integrate increased levels of renewable energy and emerging energy technologies while maintaining economic, reliable, and safe operation of the electricity grid in a manner consistent with the public interest. Studies shall be based on the balancing areas of each electrical utility. The commission shall provide an opportunity for interested parties to provide input on

the appropriate scope of the study and also to provide comments on a draft report before it is finalized. All data and information relied on by the independent consultant in preparation of the draft study shall be made available to interested parties, subject to appropriate confidentiality protections, during the public comment period. The results of the independent study shall be reported to the General Assembly.

(B) The commission may require regular updates from utilities regarding the implementation of the state's renewable energy policies.

(C) The commission may hire or retain a consultant to assist with the independent study authorized by this section. The commission is exempt from complying with the State Procurement Code in the selection and hiring of the consultant authorized by this subsection."

I believe the process laid out in this statute is sound and would provide a transparent and independent approach to determining the true integration needs and related costs for South Carolina utilities. In contrast, the integration study performed by DESC in this proceeding did not include "an opportunity for interested parties to provide input on the appropriate scope of the study" nor did it provide for "comments on a draft report before it is finalized." Thus, rather than rely solely on a study commissioned by DESC with no peer review or input from outside stakeholders in this proceeding, I believe the process defined by Act 62 better serves the public interest and would be more appropriate for investigating whether a VIC is necessary and what the magnitude of such a charge should be.

Q. What is your recommendation for the VIC and EIC in this proceeding?

A. I recommend that the PSC consider whether a VIC or EIC is warranted, and determine the level of the VIC or EIC (if any), *only after* ORS' independent study is completed, as outlined by Act 62.

B. <u>Flaws in the "Cost of Variable Integration" study used to support the VIC</u>

Q. Please explain why you believe the analytical model DESC used to support the proposed VIC is flawed.

A. DESC relied upon the "Cost of Variable Integration" study conducted by Navigant Consulting (Navigant Study) to determine its proposed integration charge. There are a variety of reasons to believe the model used in this study and underlying assumptions are not appropriate for determining integration costs, including the following:

1) *Islanded System:* The DESC system was inaccurately modeled largely as an islanded system with very limited transfer capability between it and neighboring systems.
2) *Volatility Profile:* The modeled solar output profile overestimates volatility and only partially accounts for the effects of geographic diversity, thus inherently overestimating integration costs.
3) *4-Hour Forecast:* The study's use of a relatively long 4-hour ahead forecast window overestimates integration costs by artificially restricting unit commitment and dispatch decisions.
4) *Reserve Requirements during Non-Solar Hours:* The analysis applies the additional

reserve requirements to all 8760 hours of the year – including non-solar hours when there should be no additional reserves needed.

i. *Islanded systems*

Q. How has DESC accounted for neighboring systems in its integration study?

A. DESC has said that "Due to the need for self-sufficiency, DESC must rely on its own generators to meet generation and reserves and cannot rely on external sources."[48]

Q. Do you agree with the assumption that DESC can only rely on its own generators at all times?

A. It depends on the time frame being considered. Within a long-term planning context, it may be inappropriate for DESC to assume it can regularly rely on its neighbors for generation and reserves. However, the Cost of Variable Integration is primarily an operational study that evaluates costs on a 5-minute basis assuming a fixed set of planning assumptions (e.g. generation resources). For minute to minute balancing, which is the focus of the study, it is safe to assume that there could be substantial exchange between DESC and neighboring entities. This is how the power system is operated in reality. While Balancing Authorities like DESC generally try keep their system in balance over time, it is not required (or even desirable) for DESC to keep its system perfectly balanced on a 5-minute basis. As such, it is not necessary to add substantial operating reserves to address such short-term deviations. In fact, such deviations occur quite regularly, regardless of solar.

Q. Do you have any evidence of how the imbalance between generation and load on

[48] Exhibit No. MWT-2, p 8

DESC's system regularly deviates on a 5-minute basis?

A. Yes. In fact, the metric for detecting such an imbalance within a control is commonly known as Area Control Error or ACE. In 2018, the ACE for DESC (formerly SCE&G) was as large as -412 MW over a five-minute period, meaning that it was under-generating by this amount and needed to ramp up an equivalent level.[49] In 2015, the ACE was as large as –324 MW on a five-minute basis. As shown in the figure below for 2015, the 5-minute imbalance for SCE&G in 2015 regularly deviated between +/- 100 MW and sometimes was even greater.

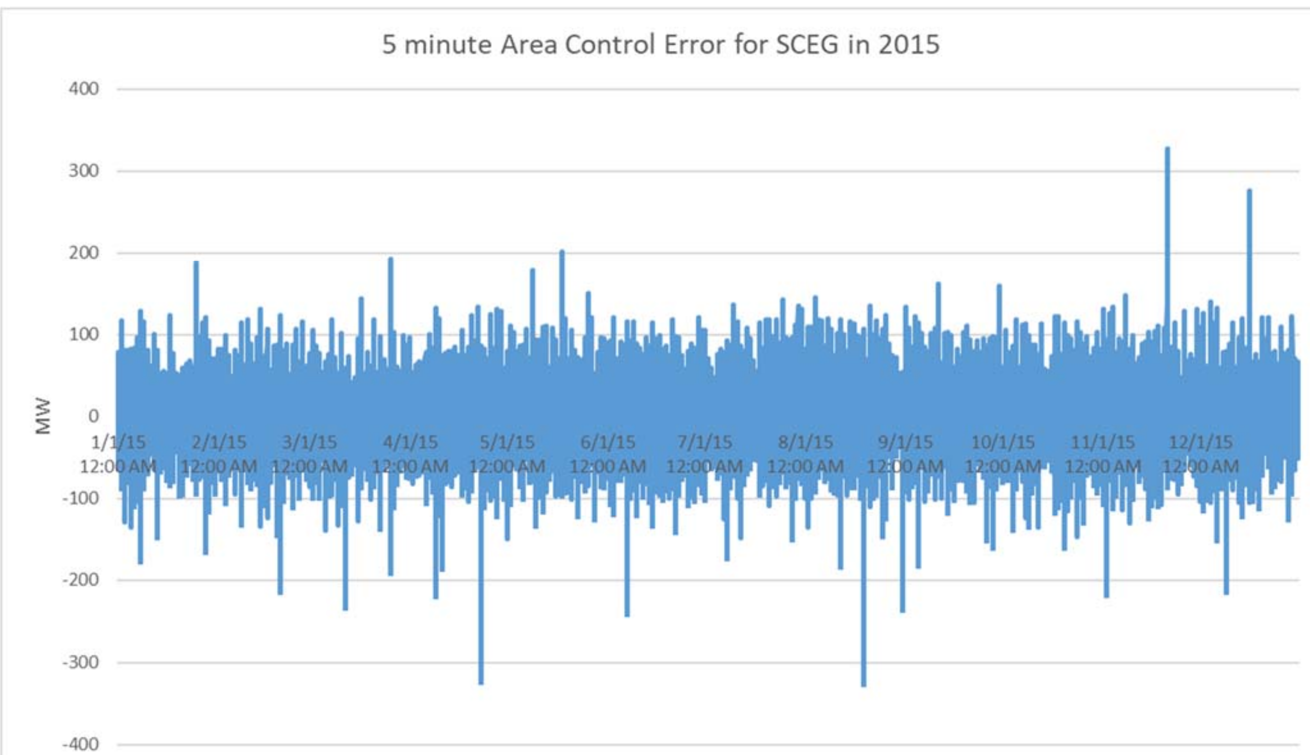

Figure 8. Five-minute load imbalances for SCE&G (2015)

[49] Based on SCEG OASIS data

Q. What else does DESC say about exchanges with external entities?

A. The integration study states that "DESC is modeled as a mostly isolated system without dynamic transmission connections to surrounding systems."[50]

Q. What are your concerns regarding the Cost of Variable Integration study's treatment of the DESC system as islanded systems?

A. My concern is that this is not a true reflection of how DESC's system truly operates. In reality, there is constant interaction between DESC's balancing areas and those surrounding it simply as a function of being interconnected to a larger system. As a simple illustrative example, the figure below shows how over a recent 2-day period DESC engaged in interchanges with its neighbors ranging from almost 900 MW in exports to almost 600 MW in imports.[51]

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[50] Ibid, p 18.

[51] https://www.eia.gov/realtime_grid/?src=data#/data/graphs?end=20190805T00&start=20190729T00&dataTypes=0g&bas=00000000000001&regions=0

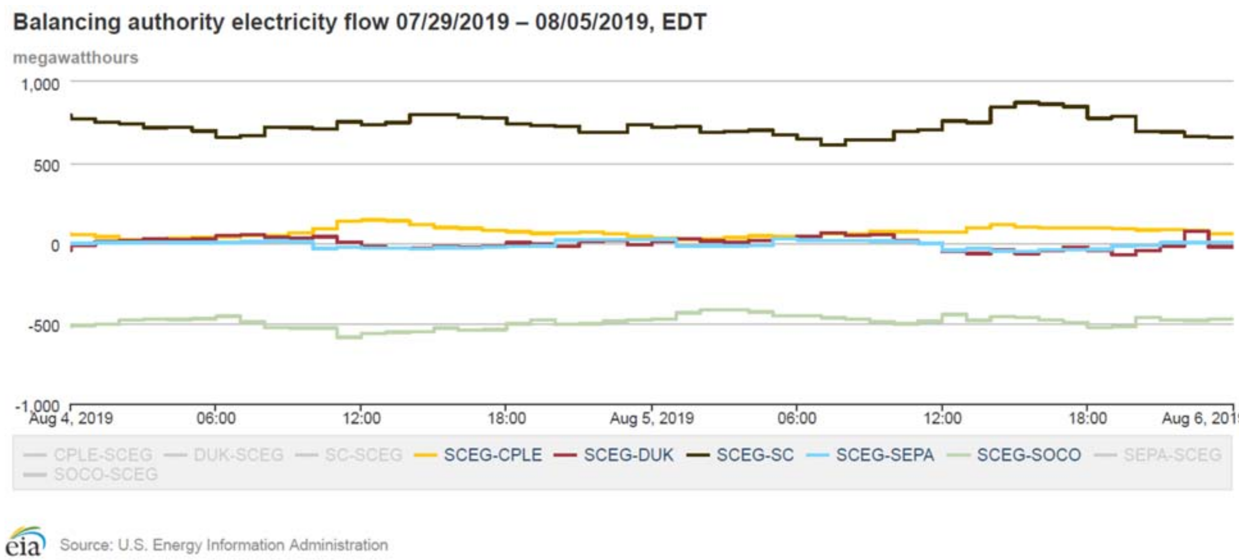

Figure 9. Interchange between DESC and neighboring areas over a two-day period

While system operators can "schedule" point to point transactions through contractual arrangements, electricity flows based on the laws of physics (not contracts) and there is frequently unscheduled flow back and forth between different areas. Stability on the grid is maintained by each operator responding in real time to maintain the overall balance of the grid's frequency when there is an imbalance.

Q. What are the implications of underestimating these interactions in terms of integration costs?

A. The implications are significant. For example, Duke recently performed a sensitivity analysis for the North Carolina Utilities Commission on its integration study wherein the operation of its two balancing areas (DEP and DEC) were assumed to be combined rather than islanded.[52] The results showed a 15% decrease in ancillary service costs (i.e. integration costs).

Q. Is this a significant change?

A. Yes. This is a significant change that stems from modeling the interaction of just two balancing authorities (i.e. DEP and DEC) as already occurs in real-world operations. In reality, there are many balancing authorities that DESC interacts with throughout the Eastern Interconnection. If all of these were appropriately modeled to reflect their interactive effects, I believe the ancillary service cost impacts would be significantly lower than what DESC modeled.

Q. What if there were a large coincident "drop" in solar generation across the entire region?

A. This would be an exceedingly rare occurrence. However, DESC is part of VACAR, a reserve sharing agreement that helps DESC maintain sufficient contingency reserves in order to respond to the single largest contingency on the system without having to hold all of the reserve requirement. Similarly, contingencies due to rare, coincident drops in solar generation could be shared among neighboring systems to avoid unnecessary buildout and operation costs. The Study identifies 196 hours of insufficient *reserves* over the period 2020-2032. Those hours do not represent a shortage of generation resources, but rather hours with a very small probability that solar generation drops significantly, in which case, reserves will be insufficient. It is important to note that this is a very rare event for which

[52] https://ieeexplore.ieee.org/document/6039888

reserve sharing arrangements could help address at a lower cost. As discussed above, the magnitude of missing reserves is comparable to contingencies that the system regularly plans for.

ii. <u>Variability of Solar Generation and Forecast Error</u>

Q. What are your concerns regarding the Navigant Study's treatment of volatility in solar output?

A. My main concern is that the model does not appropriately account for the reduction in both the forecasting error, as well as the volatility of solar generation that comes from an increasing solar fleet. An increasing number of total installed solar MW can imply both larger solar systems, as well as geographic diversity. In both cases, the variability and the forecast error of solar generation does not scale linearly with the total solar installations, as assumed in the Study.

Q. What do you mean by geographic diversity?

A. This means that the minute-to-minute variability of solar output (e.g. from clouds) typically is not replicated across many solar PV locations. Thus, if a single PV output profile, or even a small number of output profiles is used to characterize a larger deployment of solar, it may inadvertently overstate both the amount of variability experienced by utility system operators at any given hour, as well as the deviance of such generation from its forecasted value. Therefore, geographic diversity reduces both the variability, as well as the forecast error of solar generation. These reductions are not fully accounted for in the Study, resulting in an overestimation of the additional required reserves and consequently the cost of integrating solar.

Q. How does geographic diversity reduce the variability of solar generation?

A. The following chart illustrates this principle.[53] Notably the aggregation of 23 sites shows significantly reduced variability when compared to a single site or the average of five sites. This is due to the fact that environmental factors like clouds are usually uncorrelated across wider geographic areas. Thus, the variability and related ancillary service costs for solar are reduced over a larger scale.

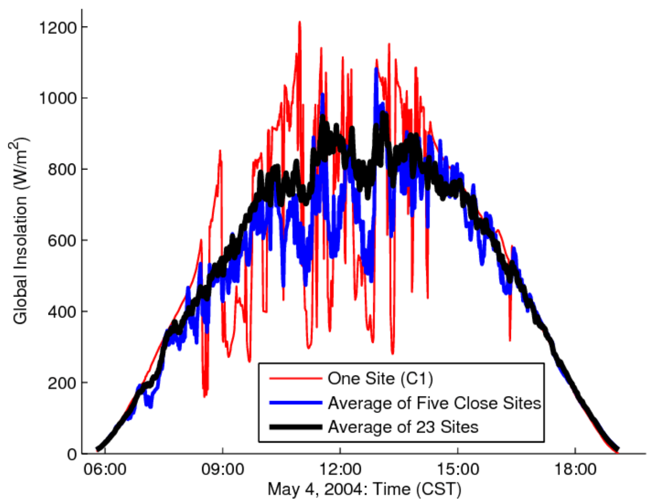

Figure 10. Impact of geographic diversity on solar variability

Q. How does geographic diversity reduce the forecast error for solar generation?

A. In addition to reducing the variability of the solar output, geographic diversity also significantly reduces the forecast error. This is conceptually acknowledged by DESC in the Navigant study, but not fully addressed within its methodology. More specifically the

[53] https://ieeexplore.ieee.org/document/6039888

study states that (page 23 of the study):

> An important part of this analysis is to consider geographic diversity when forecasting the solar uncertainty. Even in a service territory as geographically compact as DESC, spreading solar generation geographically can reduce the uncertainty. Without considering geographic diversity, the solar uncertainty would be much higher. To avoid this, the forecast error analysis was completed using NREL data located at four points around the DESC territory chosen to be near load centers. Averaging the forecast error among multiple locations properly accounts for the expected geographic diversity of solar resources being added to the system. This ensures that the analysis is not too aggressive in estimating the additional reserves needed by DESC. The table gives an example of the expected probability of losing solar generation when operating at 50% of maximum generation for the average of the four NREL points used, and for a single NREL point located near Columbia. The key result is that the uncertainty is significantly higher when estimated at a single point.

Table 10. Impact of Geographical Diversity on Solar Uncertainty

NREL Location	Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
DESC Avg.	**50%**	0.1%	0.6%	1.1%	2.1%	3.4%	7.4%	12.9%	21.8%
Columbia, SC	**50%**	3.2%	4.2%	5.2%	7.3%	10.8%	14.7%	21.3%	35.4%

Figure 11. Impact of Geographical Diversity on Solar Uncertainty (from Navigant Study)

Although this approach is a step in the right direction, the study arbitrarily limits the number of locations to four. While one can expect diminishing returns with the addition of a fifth, sixth or tenth location, each reduction in uncertainty is still meaningful and, in the aggregate, could reduce the integration charges significantly. For example, the table above shows that the probability of a 75% drop is reduced from 3.2% to 0.1% when going from one location to four. This represents a 95% improvement from the addition of just three locations. If an additional location were added in the analysis, the probability would fall even further, and in turn lower integration costs even more. No rationale is provided as to why the study was arbitrarily limited to four locations. This limitation likely overstates the forecast error. Consequently, the notion that the study fully accounts for the effect of geographic diversity is somewhat misleading.

Q. Are there other factors that DESC does not account for when estimating the variability in solar output?

A. DESC includes four solar profiles to simulate this variability. However, the Study seems to scale those profiles linearly with the total installed solar MW nameplate. For example, on page 22 of the Study, Table 8 shows the probability of a potential drop in solar production for different scenarios. According to this table, if a 100 MW solar facility was producing 50 MW in a given hour, there is a 1% probability of a 65% drop in production (i.e. from 50 MW to 17.5 MW). Similarly, the table implies that if a hypothetical 1000 MW facility were generating 500 MW, it would have the same 1% probability of a 65% drop (i.e. below 175 MW). However, this would be incorrect. As already explained, the larger 1000 MW system would have to be more geographically dispersed. This means that a cloud covering one PV panel of the 1000 MW system would be much less likely to cover all panels, when compared to the 100 MW system. Thus the chance of a 65% drop is much lower as the system scales up in size.

Q. What are the implications of this in terms of integration costs?

A. Arbitrarily limiting the number of locations and linearly scaling solar output with total installed solar MW nameplate results in overestimating the additional required reserves and the cost of variable integration.

Q. What is your recommendation regarding the solar profiles and forecast data informing the VIC?

A. I believe that the PSC should direct DESC to estimate the VIC (if any) on real-world data that more accurately represent how variability and forecast errors scale as the solar fleet grows and becomes more geographically diverse rather than modeled projections.

iii. <u>4-hour Forecast and Unit Dispatch</u>

Q. How was the forecast error estimated in the Study?

A. According to the Study, the solar forecast error is calculated as the difference between the 4-hour ahead forecast and the 5-minute actual solar generation. I believe that the use of a 4-hour ahead forecast overestimates the error, as system reserves could also be planned with a shorter time window, which would allow for a much more accurate forecast and consequently a more efficient use of resources. A 2-hour ahead forecast would be more appropriate and would result in significantly lower forecast error and thus lower the cost of unnecessary results.

Q. Would a 2-hour ahead forecast restrict the use of certain units as reserves?

A. According to the Study (pg. 8):

> Many of DESC's combustion turbine (CT) units are able to start within 15 minutes. These units provide reserves even when they are not operating. The combined cycle (CC) units require two hours or more to start if they are not operating. These units can only provide reserves if they are turned on and operating below their full capability.

Thus, even if the forecast window was shortened to 2 hours, CT units could still act as reserves even if not operating, while CC units would be reserves only when operating. Alternatively, if DESC continues to use a 4-hour ahead window, then CC units that can be turned within two hours should be considered available to act as reserves even if not operating.

Q. What are the implications of a longer forecast window in terms of integration costs?

A. Forecasting accuracy naturally increases as the forecasting window becomes shorter. A 2-hour ahead forecast would lead to lower forecast errors without reducing the availability of units to act as reserves. Using an excessive forecast of 4-hour ahead does not only lead to higher integration charges for solar, but leads to a waste of resources, by running an inefficient system with more reserves than necessary. Modern methods for forecasting solar are much shorter than 4-hours and are even as short as 5 minutes in some cases.[54]

Q. What is your recommendation regarding the solar profiles and forecast data informing the VIC?

A. The VIC should be calculated based on a more realistic shorter forecast window. A 4-hour window results in unnecessary costs for the system and ratepayers.

iv. <u>Operating Reserves during Non-Solar Hours</u>

Q. According to the Study are increased reserves required during all hours of the year?

A. No. As explained above, the additional required reserves are a function of the forecast error, which only exists when there is significant solar generation in the system. During the night, solar is not expected to generate and no additional reserves are required to hedge against a potential drop in its output. Furthermore, during other hours of the year, solar generation is low, which means that the any drop from the forecasted value is not significant enough to require additional reserves.

[54] https://www.utilitydive.com/news/how-grid-operators-forecast-weather-and-output-from-renewables/561038/

Q. How does the Study account for the fact that additional reserves are not required for all 8760 hours of a year?

A. The Study acknowledges that even if additional reserves are required to integrate higher solar penetration, these are only needed during hours of high solar generation. However, the methodology and tools used in the study fail to account for this appropriately. More specifically, PROMOD does not allow operating reserve levels to change day-to-day or hour-by-hour.[55] Therefore, in order to incorporate the days with lower requirements, Navigant calculates the costs using varying levels of operating reserves and then blends those costs using weightings tied to the proportion of days with the appropriate level of solar uncertainty.

Q. What are the implications of this blending in terms of the integration costs?

A. Requiring additional reserves for all hours of the year results in excessively and unrealistically high costs. The Study tries to address that with blending results of different runs, but this approach does not sufficiently address the error introduced by requiring the same reserves during all hours. According to the Study, the blending weights are based on the number of days in which certain levels of reserves must be maintained. However, even based on the reasoning of the Study for increased reserves, these reserves are varying by hour, and not by day. Even for days during which there is high solar generation, no additional reserves are required during night hours. Thus, the blending is inappropriate and still results in excessively high production costs.

[55] Tanner - 19

C. Flaws in DESC's Internal Analysis Supporting the Embedded Integration Charge (EIC) for Future QFs

Q. What rationale does DESC give in support of the proposed EIC for future QFs?

A. DESC claims that additional operating reserves, and associated costs, are needed to address "solar intermittency" as new solar QFs come online.

Q. How does DESC estimate the quantity of additional operating reserves needed in its model to address solar intermittency?

A. DESC assumes that additional reserves equal to 35% of the installed solar capacity are needed.

Q. Is this 35% operating reserves assumption based on any analysis or study presented in DESC's direct testimony?

A. No. DESC did later provided some analysis on solar generation that was in operation in 2018 and used this as a justification for the 35% assumption.[56] However, I do not find this analysis to be very credible.

Q. Why don't you find DESC's analysis in support of a 35% operating reserve level to be credible?

A. There are many reasons. I will list a few of them:

- DESC's analysis apparently presumes that a "drop" in solar production equates to a corresponding need for reserves on a 1:1 basis. There are many reasons why this

[56] See DESC response to SBA IR 2-14, provided on September 20, 2019.

might not be the case. For example, DESC may already have sufficient operating reserves online and would not need to add any more to meet this need.

- DESC did not provide any data or analysis of its actual operating reserves and related costs over the same time period that the solar "drops" were observed. Without corresponding data on actual reserve levels, it is impossible to validate DESC's hypothesis that the solar drops in question led to any additional costs. Moreover, it is telling that when asked to provide data on the actual amount of operating reserves held over this period, DESC claimed that this would be "unduly burdensome." Without this data, DESC's hypothesis that solar drops require additional operating reserves should be considered pure conjecture.
- All of the deficiencies that I observed in the Navigant Study also apply in this case. More specifically, the 35% assumption likely grossly overstates the level of reserves needed (and associated costs) since it does not appear to take into account any of the following:
  1) Non-islanded operations: DESC operates within the Eastern Interconnection, which is able to support short term imbalances between generation and load and can help overcome solar drops without substantial addition of new reserves.
  2) Volatility smoothing as solar scales: DESC's observations apply to a small amount of solar PV relative to expected deployment levels. As more solar is deployed, the magnitude of the "drops" will not scale up in a linear fashion, and therefore the 35% value would not hold even under DESC's approach.

3) Sub-hourly forecasting and dispatch: DESC's analysis is based on presumed level reserves needed on an hourly basis. This presumes that DESC is unwilling or unable to employ modern forecasting techniques that can predict solar closer to real-time, and ignores the fact that DESC has quick-start generation units that can ramp up in less than 30 minutes.

4) Non-solar Hours: The presumed 35% of additional reserves would not be needed during all 8760 hours of annual operation.

Q. What is the result of including this 35% assumption in DESC's calculation of avoided energy cost rates for solar?

A. DESC proposes an avoided energy cost rate for a solar QF of just $16.76/MWh for the first five years. In comparison, DESC proposes a non-solar QF rate of $32.80/MWh during peak season, peak hours (when solar is generally available). Meanwhile, DESC states that the avoided energy costs for solar if no additional integration costs (i.e. reserves) were incurred would be $23.46/MWh. This suggests an integration cost of at least $6.70/MWh. This far exceeds even what DESC's own study suggests in Exhibit No. MWT-2, which estimates integration costs ranging from $3.52-4.14/MWh. It also far exceeds what integration studies in other jurisdictions have concluded.

Q. What do you recommend the Commission should do in light of this?

A. I believe the Commission should reject DESC's approach to calculating a solar QF rate. Not only, is the 35% assumption unfounded, the resulting integration costs appear contradictory to DESC's own "Cost of Variable Integration" study. Moreover, as I demonstrated earlier in my testimony, even DESC's study is flawed and results in integration costs that are far too high. Instead of calculating a separate solar QF energy rate with an embedded integration cost (EIC) included, I recommend that the Commission require DESC to adopt a technology-neutral approach such as that proposed by Duke. Under this approach, avoided energy cost rates would be determined on their own based on time of delivery, regardless of the underlying QF technology. Meanwhile, integration costs could be analyzed and assessed separately.

Q. How could integration costs for new solar QFs be assessed under this approach?

A. First, as explained earlier in my testimony, I do not agree that any integration charge should be assessed until an independent study can be conducted. However, if the Commission chooses to approve an integration charge for new solar QFs at a later date, then I believe this charge should be calculated and applied separately from the avoided energy cost rate, similar to what DESC has proposed with its VIC. This will help provide greater transparency, and also provide flexibility to adjust the charge in the event that additional integration costs do not materialize, as has been the experience in other jurisdictions.

D. <u>Lack of Observed Integration Costs to Date</u>

Q. What are the main drivers of integration costs according to DESC's study?

A. According to DESC's study, increased amount of solar leads to an increased need to hold operating reserves which increases overall operating costs. What this means is that system operators must have generators online and ready to ramp up or down if there is a fluctuation in solar generation. This can incur some cost due to the need to turn on the load-following units, or operate other units at a suboptimal level.

Q. Is there any strong evidence that increased operating reserves have been required in the Carolinas as a result of increased solar deployment?

A. No. In fact, this issue recently came up in North Carolina's avoided cost proceeding. More specifically, Duke provided evidence that the amount of operating reserves required in 2018 have increased by about 3% from 2015 levels.[57] This stable level of operating reserves is true despite a 409% increase in solar generation in North Carolina over the same period (see table below).[58] Additionally, the amount of operating reserves actually decreases in years 2016 and 2017 (from 2015 levels) despite increasing levels of solar.

Year	**DEC/DEP Average Annual Actual Realized 60 Minute Ramping Capability in MW**		**NC solar generation (GWh, Million kWh)**	
2015	1833	-	1374	-
2016	1665	-9%	3421	+149%
2017	1595	-13%	5579	+306%
2018	1887	+3%	6997	+409%

Q. Has DESC provided similar information about its historical level of operating reserves?

A. Not to my knowledge. SBA has requested additional information on this subject and we are awaiting DESC's response.

[57] This information was reproduced in DESC's response to ORS 2-9.
[58] Energy Information Administration (EIA)" Table 1.17B Net Generation from Solar by state by sector

Q. What are the potential drivers of these changes in operating reserves other than solar?

A. As Duke recently stated in its current avoided cost proceeding before this Commission, "Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar."[59] The same is presumably true for DESC, meaning that solar is just one of many factors that may contribute to the overall need for ancillary service costs.

Q. What do you conclude from this observation?

A. There are a variety of factors that could potentially drive ancillary services and/or "integration costs" that are unrelated to incremental solar. Many of these are related simply to the existing characteristics of the utility system and others are related to the decisions and practices of its operators. As such, it is unreasonable to attribute all future incremental load following reserves (i.e. "integration costs") to solar. Such an attribution would violate the principle of cost causation.

Q. What has been the experience in other regions in terms of integration costs related to solar?

A. In general, the need for ancillary services has remained relatively static in many markets despite significant increases in renewable energy generation such as solar. As an example, the California Independent System Operator (CAISO) routinely reports on the amount of

[59] This information was provided in Duke's response to ORS 2-9.

ancillary services it procures, as well as the overall generation mix. From 2011 through 2018 (the most recent annual market report), the amount of ancillary services procured in the form of regulating reserves has not significantly increased, despite the amount of renewable energy increasing from 9% to 26%. This is illustrated in the chart below.

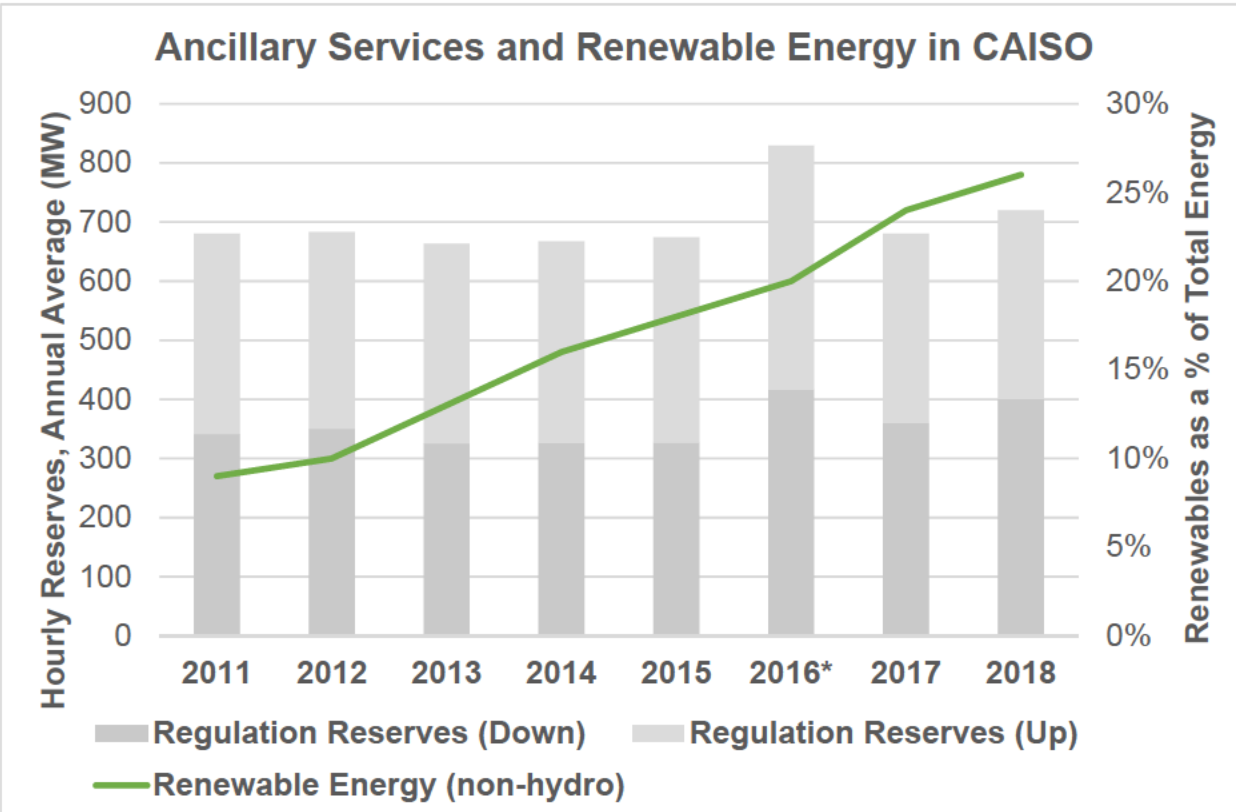

Figure 11. Trends in ancillary service requirements and renewable energy for the California Independent System Operator. (2016 requirements described in testimony below.)

One exception to this was during the spring of 2016. The CAISO anticipated a greater need for ancillary services, in part due to increased penetration of renewable energy. However, in the fall of the same year, the CAISO implemented a new methodology for determining how much ancillary services were truly needed, and the requirement fell in subsequent years.

Q. Are there steps that utilities such as DESC could take to minimize integration costs, thereby reducing costs to their customers?

A. Yes, there are many. To name a few:

- DESC could participate in a regional energy imbalance market. This has proven to be a significant benefit to utilities and their customers in the Western Interconnection, and also helps to address the costs of integrating variable renewable energy resources.
- DESC could enhance its renewable energy resource forecasting procedures. More accurate forecasting enables more efficient unit commitment and dispatch processes, thereby reducing the need for operating reserves and associated costs.
- DESC could improve the flexibility of its baseload resources. Inflexible resources are often a big driver of integration costs as renewables are added. Retrofits or operational enhancements to improve the flexibility of baseload units could help unlock these benefits for DESC's customers.

E. <u>Lack of Symmetric Compensation</u>

Q. Why do you believe that DESC's proposed approach to integration services is incomplete?

A. While DESC has addressed the possible increase in ancillary service needs due to incremental solar, it has failed to address the fact that solar can also provide ancillary services, thereby reducing overall costs to customers. Act 62 specifically requires that avoided cost calculations account for the value of ancillary services produced, as well as consumed, by QFs.

Q. Many people think of renewable resources like solar as requiring additional ancillary services to help balance their variability. Is it true that renewables can actually provide ancillary services themselves?

A. Absolutely. In fact, recent demonstrations in the CAISO have illustrated that renewable resources can actually be better at providing these services than conventional resources. The chart below provides demonstration of this in terms of a recent solar project providing regulation services more accurately than conventional resources.

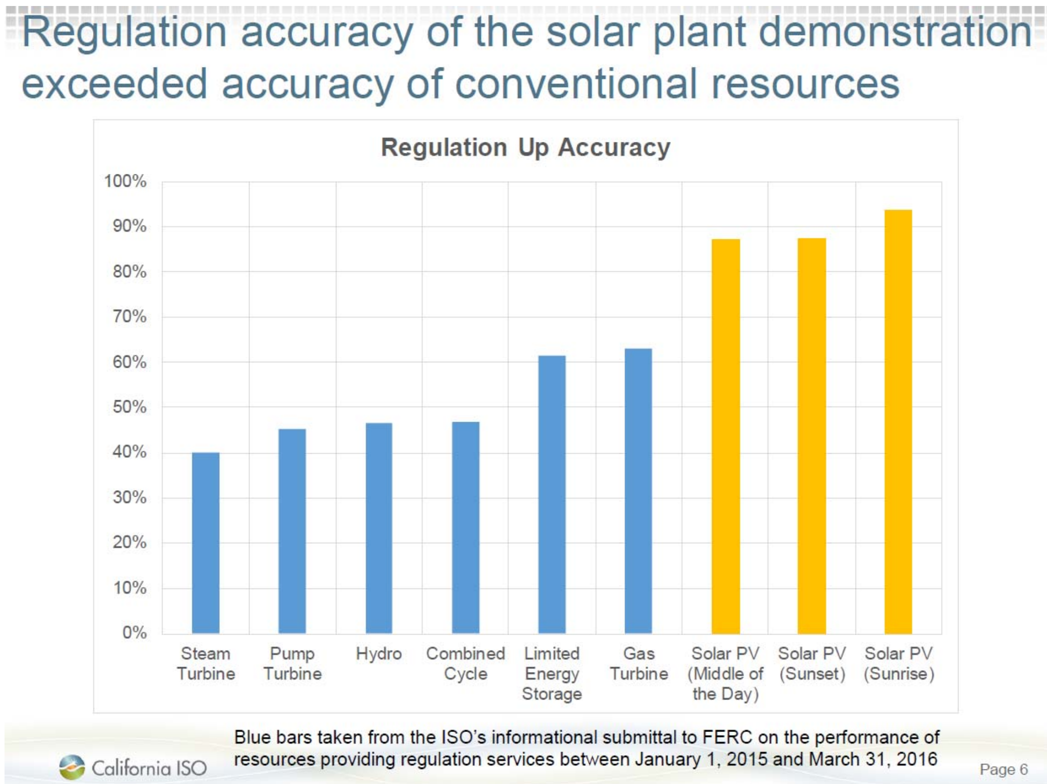

Figure 12. Ancillary services provided by the CAISO/First Solar/NREL demonstration project[60]

Q. What other methods are there for inverter-based resources (like solar) to provide ancillary services?

A. While there are many options (including simply using the capabilities of modern inverter technologies) energy storage provides additional capabilities in this regard.

Q. If QFs can provide ancillary services, how should such services be priced?

[60] https://www.caiso.com/Documents/Briefing_UsingRenewables_IncorporateRenewables-Presentation-Dec2016.pdf

A. Under existing law, DESC provides an Open Access Transmission Tariff (OATT) that provides published schedules for many of the ancillary services it offers.[61] This could be starting point for any ancillary services provided by QFs under a PURPA contract.

F. <u>Form of Proposed VIC and Alternative Integration Charge Computation</u>

Q. Given the shortcomings you have outlined regarding DESC's proposed VIC, what do you recommend instead?

A. First and foremost, I recommend that the Commission reject considering any VIC until the independent integration study authorized by Act 62 is completed. The reason for rejecting this charge are due to the fact that:

- It is premature to impose a VIC on solar QFs until an independent analysis as contemplated by Act 62.
- The analytical model DESC uses to support the proposed VIC contains several fundamental flaws.
- There is very little evidence from other regions that significant integration costs will materialize.
- DESC's proposal does not consider integration services that could be provided by solar QFs.

However, if the Commission feels compelled to adopt some sort of integration charge prior

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[61] DESC OATT: https://www.oasis.oati.com/woa/docs/SCEG/SCEGdocs/DOMINION_ENERGY_SOUTH_CAROLINA_OATT_08.09.2019.pdf

to the completion of that study, I have several recommendations for how such a charge should be implemented.

Q. What are your recommendations if the Commission does feel compelled to approve an integration charge?

A. Any integration charge should include the following features:

1. The charge should be adequately capped to ensure QF developers are not subjected to unlimited risk.
2. The level of the cap should reflect the true drivers of integration costs which are not solely attributable to solar QF resources.
3. The actual level of the charge should be based on real-world data rather than modeled projections.
4. The integration charge should be able to be mitigated through appropriate dispatch of solar, storage, or other QF technologies.

Q. Can you please describe each of these features in greater detail?

A. Yes. I've addressed each of these in my testimony below.

i. <u>Cap on Integration Charges</u>

Q. Does DESC's proposal allow the Variable Integration Charge to increase over time?

A. Based on my review of DESC's testimony in this proceeding so far I have not seen any limitation on future VIC charges.

Q. Has DESC proposed a cap on an integration charge imposed on solar facilities with VIC provisions in their PPAs?

A. Not to my knowledge.

Q. What does this mean from a QF project owner's standpoint?

A. Since the integration charge could change over time, essentially this means that all QF projects with a VIC will have to assume that they will be at risk for a VIC that could increase without restriction. This will increase project costs despite the fact that real-world examples indicate that any integration costs are likely to remain flat or even decrease over time rather than increase.

Q. What remedy might be able to resolve this?

A. If an integration charge is imposed, it is necessary (and fair) to include a reasonable cap that limits the integration charge for projects of a similar vintage to a reasonable level.

ii. *Level of Cap*

Q. What method would you propose for setting the initial level of the cap on integration charges if one is approved in this proceeding?

A. DESC's study has suggested integration costs in the range of \$3.52-\$4.14 per MWh. However, as explained above, there are a variety of shortcomings in the way these charges were estimated that need to be corrected for.

Q. How would you recommend making these corrections?

A. Ideally this would be one of the outcomes of any independent integration cost study as described earlier in my testimony. However, if one assumes DESC's proposed charges as a starting point, I would suggest the following potential modifications as an illustrative example:[62]

Modification	% Change	Resulting Integration Charge Cap ($/MWh)	Rationale
DESC's initial proposed Variable Integration Charge	--	$3.52	Based on Navigant Cost of Integration Study
Operating reserve changes during solar hours only (versus all 8760 hours)	-52%	$1.69	Approximated based on hours with no solar production (assumes SAT).
Reduced volatility profile due to geographic diversity (beyond 4 sites)	-18%	$1.39	Strategen placeholder estimate (further study is needed to accurately determine).
Non-islanded operation (rest of Eastern Interconnection)	-30%	$0.98	Strategen placeholder estimate (further study is needed to accurately determine).
Use of hourly or sub-hourly solar forecast and dispatch	-1%	$0.97	Strategen placeholder estimate (further study is needed to accurately determine)
Improvements in intra-hour dispatch, including regionally coordinated imbalance services (not attributable to QFs)	-1%	$0.96	Strategen placeholder estimate (further study is needed to accurately determine).

iii. <u>*Actual Integration Costs*</u>

Q. How do you recommend setting the actual value of the integration charge?

A. I recommend that the actual integration charge (if one is approved by this Commission) be based upon actual real-world data regarding DESC's operating reserves coincident with

[62] The table shown is intended to be an illustrative example. Strategen recognizes that there are potential interactive effects of several of these changes. Additionally, certain values were included as placeholders since additional analysis is necessary to determine more precise estimates. This is intended to highlight the numerous mitigating factors that would tend to reduce integration costs and would need to be accounted for before an integration cost cap can be set.

QF production. For example, an annual review could be conducted to determine how many MW of spinning reserves DESC committed in each hour of the year that coincided with solar QF production. A determination could be made as to whether this level of reserves was higher or lower than in previous years. If higher, then a further determination could be made as to what portion of those reserves, and associated costs, might have been attributable to solar QFs and this could then be used as the basis of the integration charge for the following year's vintage of new QF projects (though integration charges for existing QFs should not in any event be adjusted upward during the term of their contract).

Q. What caution must be taken in making this determination?

A. As Duke pointed out in its avoided cost proceeding, Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar. Thus, care must be taken to isolate the operating reserve changes that are attributable to solar versus other factors. Additionally, further care must be taken to isolate the fraction of these solar-related costs that are due to QFs versus other renewable resources on DESC's systems.

iv. Dispatchable solar QFs

Q. What special considerations should be given to solar QFs that are dispatchable?

A. As explained in my testimony above, modern inverter-based resources such as solar PV or solar PV coupled with battery storage are dispatchable resources. Like any grid resource, there are certain limitations (for example, a solar-only resource may need to pre-curtail to provide upward ramping capability), however there is a broad range of functionality that these resources can provide. These could include frequency regulation, load following, frequency response, voltage control, strategic curtailment (during constrained periods), and so on. These functionalities could be provided as a means to enhance value to the grid and in turn reduce costs to DESC's customers. If these QFs are able to provide these services I believe they should also be provided commensurate compensation. As one example, if a solar QF can reduce the variability of its output, or even offer load-following services, a reduction/elimination of integration charges would be warranted. In another case, if QFs are able to curtail during periods of negative avoided costs, they should be awarded a premium avoided energy cost rate during other hours.

Q. Do you have any recommendations for how to treat dispatchable QFs in this proceeding?

A. While there is great potential to harness the capabilities of dispatchable solar for the benefit of customers, I recognize that there are also many complexities involved. As such, I recommend that the PSC direct the parties to convene a working group to develop a PPA structure which would support these features.

Q. Does this conclude your testimony?

A. No. Following the close of business on the business day prior to the filing deadline,[63] DESC

[63] Specifically, at 5:14 p.m. on Friday, September 20, 2019, DESC filed and served on all parties amended Direct Testimony of James W. Neely, amended Direct Testimony of John E. Folsom, Jr., and amended exhibits to the amended Direct Testimony of John E. Folsom, Jr. and to the Direct Testimony of Allen W. Rooks.

filed amended versions of two witnesses' testimony, as well as nine (9) amended exhibits. The amended testimony reflected changes in Dominion's avoided cost calculation methodology and substantial changes in the proposed rates. Later that same evening, Dominion served corrected and supplemental versions of a number of previously-provided discovery responses. I have had only a very short time to review and analyze these new filings. As such, I reserve the right to amend this testimony and/or file supplemental direct testimony addressing Dominion's revised testimony and discovery responses.

EXHIBIT EAB-1: Ed Burgess Full Resume

Edward Burgess
eburgess@strategen.com
941-266-0017

Overview

Ed Burgess is Senior Director of Strategen Consulting's Government and Utility Consulting Practice. His core expertise is in policy and regulation of the electric power sector at the state level, with a specialized focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design. Ed has served clients in the renewable energy, energy storage, electric vehicle, and energy efficiency industries, including several private companies, energy project developers, trade associations, utilities, government agencies, and foundations. His technical analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed energy resources, rate design, resource planning and transmission/distribution system planning. Prior to joining Strategen, Ed played a lead role in two major initiatives at Arizona State University: The Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona. Ed also worked as an independent consultant for Schlegel & Associates, providing technical analysis on demand-side management policies, and for Kris Mayes Law Firm providing regulatory support to the solar industry in the Southwest U.S.

Senior Director
AUG 2019 – Present
Director
JAN 2018 – AUG 2019
Senior Manager
JUL 2016 – DEC 2017
Manager
JUL 2015 – JUN 2016
Strategen Consulting – Berkeley, CA

Independent Consultant
NOV 2012 – JUL 2015
Schlegel & Associates – Phoenix, AZ
JUN 2012 – JUL 2015
Kris Mayes Law Firm – Phoenix, AZ

Project Manager & Researcher
JUN 2012 – JUL 2015
Arizona State University – Tempe, AZ

Instructor
JUN 2011 – MAY 2012

EDUCATION

PSM, Solar Energy Engineering and Commercialization
Arizona State University, 2012

MS, Sustainability
Arizona State University, 2011

BA, Chemistry
Princeton University, 2007

EXPERIENCE – 11 YEARS

- Energy Resource Planning & Procurement
- Utility Rates and Regulation
- Cost Benefit Analysis
- Avoided Cost and Cost Effectiveness
- Energy Policy & Markets
- Energy Product Development & Market Strategy
- Stakeholder Engagement
- Management Consulting

Arizona State University School of Sustainability – Tempe, AZ

Research Fellow
JUL 2007 – JUL 2009
Environmental Defense Fund – New York, NY

EXPERT TESTIMONY

National Grid, Electric Vehicle Infrastructure Program Docket No 18-150

Selection of Relevant Projects at Strategen Consulting

Massachusetts Attorney General's Office

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of the Consumer Advocate

- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources.
- Developed a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

District of Columbia, Office of the People's Counsel

- Provided technical support and analysis on a utility proposed electric vehicle charging program
- Supported drafting comments on the Counsel's position in favor of a more customer-friendly approach to electric vehicle program implementation

North Carolina, Office of the Attorney General

- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.

Maryland, Office of People's Counsel

- Provided technical support to the state's consumer advocate topics associated with the large PC44 grid modernization effort.
- Topics included electric vehicles, energy storage, distribution grid planning, and interconnection.

Arizona, Residential Utility Consumer Office (RUCO)

- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Portland General Electric

- Provided education and strategic guidance to a major investor-owned utility on the

potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for potential storage technology solution providers.

Xcel Energy
- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

City and County of San Francisco
- Aided in evaluation of solar PV with battery storage as a solution for resilience of critical infrastructure.
- Provided technical economic assessment of opportunities for wholesale market participation as an added value for facilities installed.

University of California, San Diego
- Conducted economic analysis to help guide a multi-year research project on the use of advanced solar forecasting technology to improve integrated solar and energy storage.

University of Minnesota
- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

Arizona State University (ASU)/Arizona Department of Environmental Quality (ADEQ)
- Project manager for partnership between ASU/ADEQ to study compliance options for the state of Arizona to meet requirements of the EPA's Clean Power Plan (CPP).
- Completed a comprehensive study on the impact of CPP scenarios on the operation of the southwest power grid and cost to Arizona and Navajo Nation electricity customers.

Recent Publications
- Edward Burgess, Ellen Zuckerman, and Jeff Schlegel, "Is the Duck Curve Eroding the Value of Energy Efficiency" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2018 Summer Study on Energy Efficiency in Buildings, (pending).
- Lon Huber, Ed Burgess, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," (November 2016), Arizona Residential Utility Consumer Office,

Arizona Corporation Commission, Docket No. E-00000Q-16-0289, https://www.strategen.com/s/Evolving-the-RPS-Whitepaper.pdf

- Mark Higgins, Ed Burgess, and Bill Ehrlich, "Energy Storage Likely to Increase in Utility Resource Planning" Natural Gas and Electricity, Volume 32, Number 10 (May 2016).
- Ellen Zuckerman, Edward Burgess, and Jeff Schlegel, "Are Recent Forays into Restructuring a Threat to Energy Efficiency?" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2014 Summer Study on Energy Efficiency in Buildings, (August 2014) http://aceee.org/files/proceedings/2014/data/papers/6-1135.pdf#page=1.
- Sonia Aggarwal and Edward Burgess, "Performance Based Models to Address Regulatory Challenges" The Electricity Journal (July 2014) http://www.sciencedirect.com/science/article/pii/S1040619014001389.
- "Transmission and Renewable Energy Planning in California," prepared for the Western Governors Association, (November 2012) http://www.westgov.org/wieb/wrez/11-28-2012WREZca.pdf.
- Edward Burgess and Petra Todorovich, "High-Speed Rail and Reducing Oil Dependence" in Transport Beyond Oil, Island Press (March 2013).
- "On the nature of the dirty ice at the bottom of the GISP2 ice core," Earth & Planetary Science Letters (October 2010). http://www.sciencedirect.com/science/article/pii/S0012821X10006084

Selected Speaking Engagements

- California Energy Storage Alliance, Market Development Forum (February 2019)
- Rutgers University, Rutgers Energy Institute 2018 Annual Symposium (May 2018)
- Energy Storage North America (August 2017)
- MN Energy Storage Workshop (Sept 2016 & Jan 2017);
- Arizona Corporation Commission Peak Demand Workshop, (August 2016);
- Arizona Department of Environmental Quality, Clean Power Plan Technical Working Group, (May 2016);
- Energy Storage North America (2015);
- ASU Clean Power Workshop (February 2015);
- Western Interstate Energy Board Meeting (March 2014).